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DEVELOPMENT OF NATURAL GAS AND OIL RESOURCES ON THE OUTER CONTINENTAL SHELF

HEARING

BEFORE THE

SUBCOMMITTEE ON OCEANOGRAPHY, GULF OF MEXICO, AND THE OUTER CONTINENTAL SHELF

OF THE

COMMITTEE ON MERCHANT MARINE AND FISHERIES HOUSE OF REPRESENTATIVES

ONE HUNDRED THIRD CONGRESS

FIRST SESSION

ON

H.R. 1282

A bill to provide enhanced energy security through incentives to explore and develop frontier areas of the Outer Continental Shelf and to enhance production of the domestic oil and gas resources in deep water areas of the Outer Continental Shelf

SEPTEMBER 14, 1993

Serial No. 103-58

Printed for the use of the Committee on Merchant Marine and Fisheries

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DEVELOPMENT OF NATURAL GAS AND OIL RESOURCES ON THE OUTER CONTINENTAL SHELF

TUESDAY, SEPTEMBER 14, 1993

HOUSE OF REPRESENTATIVES, SUBCOMMITTEE ON OCEANOGRAPHY, GULF OF MEXICO, AND THE OUTER CONTINENTAL SHELF, COMMITTEE ON MERCHANT MARINE AND FISHERIES,

Washington, DC.

The Subcommittee met, pursuant to call, at 2:14 p.m., in room 1334, Longworth House Office Building, Hon. Solomon P. Ortiz [chairman of the Subcommittee] presiding.

Present: Representatives Ortiz, Green, Laughlin and Weldon.

Staff Present: Jeffrey Pike, Chief of Staff; Tom Kitsos, Chief Counsel; Sue Waldron, Press Secretary; Sheila McCready, Staff Director; Robert Wharton, Terry Schaff, Greg Gould, and Chris Mann, Professional Staff; John Aguirre, Clerk; Harry Burroughs, Minority Staff Director; Cynthia Wilkinson, Minority Chief Counsel; Richard Russell, Dave Whaley, Laurel Bryant, and Margherita Woods, Minority Professional Staff.

Mr. ORTIZ. The hearing will come to order. And I think we are having a little disruption as we move along this hearing, within the next 10 to 15 minutes, but good afternoon.

STATEMENT OF HON. SOLOMON P. ORTIZ, A U.S. REPRESENTATIVE FROM TEXAS, AND CHAIRMAN, SUBCOMMITTEE ON OCEANOGRAPHY, GULF OF MEXICO, AND THE OUTER CONTINENTAL SHELF

Mr. ORTIZ. I would like to welcome all of you here today on behalf of the Subcommittee on Oceanography, Gulf of Mexico and the Outer Continental Shelf.

Today, the Subcommittee meets to hear comments on H.R. 1282, the Outer Continental Shelf Enhanced Exploration and Deep Water Incentives Act, and other legislative proposals to provide incentives for deep water and frontier area OCS development. We will also be receiving information on current and future deep water and arctic drilling and production technologies.

The deep water areas of the Gulf of Mexico and the areas of the Arctic Ocean and offshore Alaska represent some of the best prospects for new oil and gas discovery in the United States. However, development in these areas has slowed in recent years due to the high cost of technology required to operate in these extreme environments.

During the 1980's, the price of oil averaged over $30 per barrel. However, in 1986, the price dropped to under $20 and has remained there ever since. This drop in price resulted in a decline in domestic oil and gas production, as developmental costs exceeded the profits that could be obtained from marginal natural gas and oil fields. This drop in price, along with the associated decline in domestic production, is believed to have been a major factor in the loss of over a half million jobs within the oil and gas industry over the past decade.

Since 1991, over 175 oil and gas discoveries have been made in deep water areas of the Gulf Mexico. These discoveries are estimated to contain over four billion barrels of oil equivalent. However, due to the costs associated with developing these prospects, industry has not announced plans to develop most of these discoveries.

With this hearing, the Subcommittee is continuing its review of the Nation's offshore oil and gas program. The purpose of this hearing today is to examine the need for incentives to promote the development of marginal and costly offshore prospects and to assess the cost to the Federal Government of providing these various incentives. Development of these prospects, in an environmentally sound manner, will lead to substantial new job creation and economic growth for the Nation and will help to reduce our dependence on foreign oil.

I look forward to hearing from the distinguished group of witnesses that we have assembled before us today, and I thank you for being with us today.

Mr. ORTIZ. Now I yield to my good friend and Ranking Member, Mr. Weldon, for an opening statement.

STATEMENT OF HON. CURT WELDON, A U.S. REPRESENTATIVE FROM PENNSYLVANIA

Mr. WELDON. Thank you, Mr. Chairman, and I want to thank you for holding this very important hearing and for our distinguished panel for coming and testifying today.

I apologize in advance that we will have to leave. We expect another vote to come about in approximately 15 minutes, so we will be interrupted, but we will be back again for this very important session.

Mr. Chairman and our full Ranking Committee Member have worked for years in finding ways to decrease our Nation's dependence on import oil, and this hearing is simply another step in that process as we move toward a sustainable national energy policy which will in the long-term ensure our energy security.

I have always believed in the importance of reliable and environmentally sound energy sources, and since the Gulf War there certainly has been renewed interest in the part of this body, the Congress, in terms of our energy independence.

In 1992, as you all know, Congress passed and the President signed the first comprehensive national energy strategy in over a decade. Although it was a step in the right direction, it is a very small step toward reducing and establishing our independence on imported oil.

As a matter of fact, one of the things that Congressman Greg Laughlin and I have done is formed an energy caucus to work with our counterparts in the Russian parliament.

Today, the U.S. consumes 29 percent of the world's annual production, yet our known reserves account for only 2.5 percent of the world's oil supply. Those figures are not sustainable.

Conservation obviously plays an important role, and we all have been strong advocates of alternative fuel programs and conservation issues. However, conservation alone, many of us feel, is not going to solve the problem. New sources of energy must be found.

As the recent discovery of a Mars field in the Gulf Mexico illustrates, deep and ultra-deep water exploration has the potential to significantly increase our Nation's oil production. For this reason, deep water exploration seems to be a promising outlet to travel in meeting some of our future energy needs.

However, there are some questions, and I hope that we can answer some of these today, and I would ask the panelists to consider these. Is deep water drilling cost effective? Will the incentives provided by H.R. 1282 be sufficient to promote deep water exploration? How much will H.R. 1282 cost the taxpayer? Is deep water drilling an environmentally sound process? These are questions that I hope we will hear the answers to today from our distinguished panelists.

Once again I want to compliment you, Mr. Chairman, for your leadership and thank all of you for coming in today.

Mr. ORTIZ. Let me introduce our first panel, which consists of representatives from the administration and the oil and gas industry. They are here to speak directly on H.R. 1282 and other proposals to provide incentives for offshore oil and gas development.

First is Mr. Tom Fry, Director of the Minerals Management Service within the Department of Interior. Next is Mr. John Riggs, Principal Deputy Assistant Secretary for the Office of Policy, Planning and Program Evaluation within the Department of Energy. And last but not least is Mr. Bob Stewart, President of the National Ocean Industries Association, which is a trade association that represents roughly 250 companies that are engaged in all aspects of exploring for and producing oil from the Nation's outer continental shelf.

Mr. ORTIZ. I welcome all of you to the Subcommittee and appreciate you being here with us today. And I think that we can start with Mr. Fry with his testimony.

STATEMENT OF TOM FRY, DIRECTOR, MINERALS MANAGEMENT SERVICE, U.S. DEPARTMENT OF THE INTERIOR

Mr. FRY. Thank you very much, Mr. Chairman. It is a pleasure to be here and to testify before this Committee and to also participate on this panel with my friend, Mr. Riggs, and Mr. Stewart. We do appreciate the opportunity to be here.

I have prepared some written testimony which I would—am not going to read for you today. However, I would ask that that be made a part of the record.

Mr. ORTIZ. Hearing no objection, it will be part of the record.

Mr. FRY. Thank you very much, sir.

Today, I would like to generally talk about the bill that this Committee has asked us to consider. The bill was drafted, I think, to encourage offshore development, specifically, deep water offshore development. We would support the general goals of that bill. There are some things that I would like to point out about the bill that I think might make it more effective, but in general, we do support measures that will encourage additional production in deep water and in frontier areas.

I should say that, as I came today, I found that we are having a sale in the Western Gulf of Mexico tomorrow morning. All the bids now are in. And I can tell you that last year we had 81 bids on 61 tracts. This year, I can tell you that although we haven't opened any bids yet so we don't know what they say—we have 197 bids on 157 tracts. That indicates to me that there is some renewed interest in activity in the Gulf of Mexico.

Obviously, bid activity is going to be price-driven. Gas prices are a little higher today than they were a year ago, so that may have some effect on what we have seen from the bids. But it is encouraging to me to see additional bidding going on.

To briefly talk about where we find ourself today, the Secretary of Interior currently has the authority under law to set the royalty rates prior to leasing. There are certain royalty amounts that the Secretary cannot go under without coming to Congress for approval, but, generally speaking, the Secretary does have the authority to set royalty rates on new leases or reduce royalty rates on existing leases in certain areas. That will be something, depending on the outcome of this legislation and other legislative proposals, that we may want to consider on our own.

The second area for consideration is the period of time between the time a lease is granted and production occurs. For non-producing leases, it is very unclear as to what the Department's authority is to engage in royalty reduction during that period. Therefore, we would be happy to see legislation that would clarify what our authority is. Our Solicitor's office is looking at this and has said we may have the authority, but we may not have the authority. So it would be much nicer to have a clear mandate from this legislative body that tells us exactly what our authorities are in that area.

We clearly have the authority after production begins to reduce royalties. In fact, I have had the opportunity to participate already in one such royalty rate reduction case where we have granted a royalty rate reduction in order to encourage the continuation of production so that production did not stop.

So that is where we find ourselves in terms of our ability within the Department to engage in some sort of royalty rate reduction.

The only other thing that I would like to point out initially is that we think that any bill passed by the Congress should ensure that there is not a disproportionate gain to any individual party from a mandatory royalty suspension.

We have done some analysis within the Department of Interior. We would like to share that analysis with this Committee and also with the industry so that they can tell us whether our analysis is correct. But the analysis indicates that a royalty suspension on existing leases in the Gulf in 200- to 400-meter water depths will probably not cause additional production. However, we do estimate that additional production may be encouraged with royalty relief on two discoveries in a water depth range of over 400 meters.

So we would like to share that information because we want to make sure that if someone is given a royalty suspension that suspension does not contribute unfairly to their benefit but does encourage new production.

Mr. ORTIZ. Thank you.

[The statement of Mr. Fry can be found at the end of the hearing.]

Mr. ORTIZ. I hate to intervene now, but we do have a vote, and we have got about nine minutes left. We will go vote and then after this vote on an amendment we have final passage, so we will have two votes, but I can assure you we will run back as fast as we can. Thank you.

[Recess.]

Mr. ORTIZ. I am sorry about the interruption, but I can assure you that there will be more interruptions as we move along.

Now we will have Mr. Riggs, and you can go ahead and start with your testimony, sir.

STATEMENT OF JOHN RIGGS, PRINCIPAL DEPUTY ASSISTANT SECRETARY, OFFICE OF POLICY, PLANNING AND PROGRAM EVALUATION, U.S. DEPARTMENT OF ENERGY

Mr. RIGGS. Thank you, Mr. Chairman.

I am Jack Riggs. I am representing the Department of Energy, and, with your permission, I would like to insert my written text in the record of the hearing and summarize.

Mr. ORTIZ. It will be included for the record, yes, sir.

Mr. RIGGS. Thank you.

Let me say at the outset that the Department of Energy agrees with the Department of Interior's recommendations on H.R. 1282, and I would like to, in my summary, approach the issue from a broader perspective.

As the written testimony indicates, the oil and gas industry is crucial to our economy—as you know as well as anyone, in terms of its importance to energy security, to the balance of trade and to the creation of high-tech, high-paying jobs in this country. By many measures, the loss of jobs, rig counts, increased imports, reduced production, the industry has declined over the past decade.

In recognition of that fact, Secretary O'Leary has asked the Department to prepare a domestic gas and oil initiative, and we are working on that right now, seeking to define proposals for strengthening the industry in ways that are consistent with the overall health of the economy and of the environment and the administration's deficit reduction plans.

Offshore production is an integral part of the industry. It is responsible for about 10 percent of our oil production and about 25 percent of our gas production. Offshore production, both deep and shallow, therefore, will be an important focus of this domestic gas and oil initiative. We in the Department of Energy are proposing to establish with Interior a working group to focus on the issues that are primarily within the jurisdiction of Interior. At the same time, as we try to stimulate this segment of the industry, we want to make sure that everything we recommend is consistent with the highest environmental standards.

One goal—one potential goal of this initiative is to strongly encourage energy companies with a choice of prospects for their exploration and production in the U.S.. That adds value in terms of energy security, in terms of balance of trade, in terms of jobs, and, in the case of deep water production, in the development of innovative drilling techniques that not only make currently uneconomic prospects profitable but that will also help keep U.S. leadership in this industry.

But the value of producing that marginal barrel or MCF domestically is not unlimited. Whether to pay a premium and how much for domestic production is one of the toughest analytical tasks that we have to undertake. The assumptions that are made will dictate the conclusions, and these assumptions are frequently made based more on values than on facts.

If deciding to pay a premium or offer an incentive for domestic production is tough, the effort to justify incentives for some types of production over others is even tougher. As Mr. Weldon said in his opening statement, is deep water drilling cost-effective? That is one of the key questions on what kind of incentives we need to offer to bring more on.

In some cases, the very large potential resources will justify a decision to go after the more expensive production, but we learned in the 1970's and in the 1980's, I hope, to be careful about substituting our judgment for that of the market, favoring some categories of gas and oil over others, and we have to approach these decisions with a rigorous analytical effort. It is with that effort in mind that we hope to cooperate with Interior and try to define some of these options.

In the case of H.R. 1282, which would give royalty relief to production from certain categories of offshore oil and gas, this caution informs our judgment and leads DOE to agree with Interior's balanced approach.

First, we agree that some royalty relief may be justified for new leases in deep water, in part because increased bonus bids and, we hope, taxes from increased production will largely offset the revenue losses. We will defer to Interior's expertise on the question of whether 200 meters or 400 meters should be the threshold for this incentive.

Second, on existing leases, Interior, as Mr. Fry has stated, may now have the authority to grant royalty relief on a case-by-case basis, and we presume it will be exercised to provide incentives for production that would not otherwise occur. We are not eager to have more free riders than we have new production from such incentives. I think Interior's examination of 30 discoveries in the Gulf and finding that the royalty relief would only affect the production decision for two of them provides a powerful cautionary note to the exercise of this authority.

Finally, on the provision allowing designation of frontier areas eligible for royalty relief, we again would defer to Interior's expertise and judgment that current law allows them to achieve this purpose more efficiently.

That concludes my remarks, Mr. Chairman, and I would be happy to answer questions.

Mr. ORTIZ. Thank you very much.

[The statement of Mr. Riggs can be found at the end of the hearing.]

Mr. ORTIZ. And now we can move to Mr. Stewart with his testimony.

STATEMENT OF ROBERT STEWART, PRESIDENT, NATIONAL OCEAN INDUSTRIES ASSOCIATION

Mr. STEWART. Thank you, Mr. Chairman.

I am Bob Stewart with the National Ocean Industries Association. Endorsing our statement this afternoon is the International Association of Drilling Contractors, the International Association of Geophysical Contractors and the Petroleum Equipment Suppliers Association.

I want to thank you, Mr. Chairman, for inviting us here to testify. I also want to offer thanks for the gracious cooperation we have gotten from the Subcommittee staff.

It pains me to have to start out by pointing out that there is an error in our statement, but I need to correct it for the record. On the third page of text, in the second full paragraph, there is a sentence that reads, in part, the DRI study found that incentives that spurred the development of 2 to 7 billion barrels of oil equivalent should read 2 to 9 billion barrels of oil equivalent. So if we can make that correction, it would be much appreciated.

Mr. ORTIZ. We will make sure that the staff makes the correction on that.

Mr. STEWART. It is a real pleasure to come up here to address a proposal, a piece of legislation that proposes to do something for this industry rather than do something to it. We have discussed here this afternoon already the level of distress that this industry has been in, and I am not going to dwell on that any further except to say that any proposal that is made in the Congress that would serve in some manner to ease that distress is very welcome.

Mr. Fry has already gone over a good bit of my statement, but I will touch it very lightly.

The Secretary does indeed have authority under the Outer Continental Shelf Lands Act to either reduce or eliminate royalties to prevent premature abandonment of producing properties. It is our belief that that same section of the OSC Lands Act, namely Section 8(a)(3), also clothes the Secretary with the authority to act prospectively. That is to both reduce or eliminate royalties on a lease where an exploratory well has been drilled. But when there is a decision to develop, it probably is going to be a negative because the economics are marginal, and we believe a very strong and compelling case can be made that the legislation—the OCS Lands Act—already gives the Secretary that authority.

We would certainly support what Mr. Fry called for, that is, wiping away any lingering questions about the existence of that authority through legislation. We would have no objection to that at all.

Finally, as far as deep water is concerned, as I say, we find Mr. Fields' bill very, very welcome. There is no question that the deep water Gulf of Mexico is basically a new frontier. The geology is less well-known out there than it is in the shallower Gulf of Mexico. The infrastructure in many parts of the deep water needs to be built. It is not there. The costs associated with working in deep water are necessarily higher.

In answer to one of Mr. Weldon's questions, however, the environmental risks associated with deep water development are, in my view, not any greater than they are in the shallow water. And in the shallow water this industry's record—environmental record—has been nothing short of superb.

So, in closing, let me commend the Subcommittee for considering a piece of legislation of the sort that Mr. Fields has introduced, and I hope to be able to work cooperatively with the Subcommittee as well as with the Department of Interior and the Department of Energy to develop this proposal. Thank you very much.

Mr. ORTIZ. Thank you.

[The statement of Mr. Stewart can be found at the end of the hearing.]

Mr. ORTIZ. We are waiting for some of the Members to come back, but I know that within the next five, six minutes there is going to be another vote, and I hope that that will be the final vote.

But I will begin by asking Mr. Stewart a question here. What effect will the proposed incentives have on industry's willingness to develop deep water or marginal areas? And what can be done to stimulate deep water or marginal areas without legislation?

Additionally, do you feel that providing royalty relief will induce enough new development that would not otherwise take place to make such a proposal justified in terms of protecting Federal revenues?

Mr. STEWART. I think, Mr. Chairman, that if this program is designed properly you should be able to avoid offering incentives to projects that would go forward anyway. That is not the objective here.

The objective, as in the case with the exercise of the secretarial authority that is already there, is to either prolong existing production or to prompt new production to come on stream that would not otherwise have been done.

There is, in that case, in our view, no loss of revenue to the Federal Government at all. You are forgiving royalties that would not have been paid anyway because either the project would have been terminated or never started. So you really haven't lost anything.

On the other hand, if you either produce a new project or extend an old one, you continue to create a line of tax revenue to the Federal Treasury. You also have an impact on jobs that is positive. So even though some may say—and we have talked in part about tax—correction—tax credits needing to be a part of the package in very deep water. People roll their eyes when you mention that and say, well, it is not possible. It is not politically doable.

You can look at the economic wallop that some of those projects produce—and there is an example of one of them in our written statement in terms of jobs, in terms of hundreds of contracts going, in the case of the one project we cite to 33 different States. The economic wallop is sufficiently large that you may look at relief and tax credits and think it is a bargain for the American people.

Mr. ORTIZ. Thank you.

Mr. Riggs, how does the proposed legislation fit into DOE's national energy initiative and are there other ways to stimulate domestic offshore oil and gas exploration, development and production?

Mr. RIGGS. Mr. Chairman, this is clearly one potential option that would be the type of thing that could be included in the domestic gas and oil initiative and one that is being examined in our current discussions. At this point, they are still in the discussion stage, and I can't say that it will or will not be included. We clearly want to cooperate closely with Interior on items dealing with public lands.

Other examples of things that could stimulate additional production include: additional flexibilities in royalty and bonus payments—again, Interior has the expertise here; potentially a sliding scale of royalties with a reduction up front and higher royalties later on if a discovery is a large one; incentives for the use of new technologies that might bring on some of these more difficult frontier areas; and the use of technology from DOE's national laboratories.

There is a lot of excitement in the industry, I believe, and in the Department about 3D seismic technology, and it is my understanding that some of the information available from previous seismic shoots in the Gulf could be more fully utilized with better computer technology that we may have available through Sandia or Los Alamos, some of the DOE labs.

In general, I would say that, in working with the Department of Interior, we would hope to identify options that would be useful in this area.

Mr. ORTIZ. I think I am going to have to recess for a few minutes. I hope that this is the last vote, and I am pretty sure that some of the other Members will be back, so the Committee will stand adjourned for a few minutes.

[Recess.]

Mr. ORTIZ. Again, somebody lied to me. They said there is one more vote somewhere within the next 15 to 20 minutes, and I really apologize for all the inconveniences that we have had throughout the hearing. Some of the other Members should be coming back soon, I hope. We just have my distinguished—my good friend and colleague from Texas, Mr. Green.

Mr. Fry, I am going to ask you a question. What impact will these incentives have on the Federal budget deficit? Now, how do the short-term revenue losses from royalty relief compare with the potential overall increases to OCS royalty from these revenues—maybe you can elaborate a little bit on that.

Mr. FRY. Yes, Mr. Chairman. I am not sure I know the ultimate answer to that question, but I would like to share some thoughts on that.

I think in the initial years, in the first couple of years of a program like this, it will probably have a positive impact on deficit reduction because I think you will see—to the extent that there are reduced royalties, you will end up seeing increased bonuses. So when we have lease sales, people will probably bid a little higher for tracts because they know they are not going to have a royalty obligation.

But our analysis has indicated that in the long-term, in the out-years—we are talking about throughout the life of the production—under the current configuration of the bill, there would probably be a substantial decrease in royalty revenues paid to the Federal Government because of the lack of the royalty being paid. So when you look at the revenue impacts in the greater scheme of things, the bonuses are a very small portion of the revenues that are received by the Federal Government, and most of what is received is on the royalty side.

Our analysis indicated that some of the projects under some of the different types of legislation we have looked at might never get to the point where a royalty provision or royalty ever kicked in, so there could be substantial losses in the long-term if we do not structure a statute or a program that only encourages people to go forward on a real incentive basis rather than on some other basis.

Mr. ORTIZ. You know, I can understand the loss of revenue, but I think that Mr. Stewart made some good points as well. You know, of course, there is a lot of uncertainty out there, but it would be great if we didn't have to be so dependent on foreign oil and if we could see more people employed. But there is a gray area out there.

But before I go any further, I would like to yield to my good friend and colleague from Texas, Mr. Green, and see if he has got any other questions.

Mr. GREEN. Thank you, Mr. Chairman.

Again, I apologize to our panel and—for having so many votes today. It seems like every 20 minutes, as soon as we come back, we have to go back over and vote.

This issue is important to me, I know, just like our Chairman, because of the districts that we represent. I have Port Houston and the east part of the county particularly, and we have a great many people who need their livelihood or develop their livelihood from offshore drilling and offshore technology. And I noticed in the—that in 1991 there were 175 discoveries in deep water areas and only 23 were developed, and I imagine cost is the biggest problem because of deep water.

But also knowing what is happening to the market now—and some of us are concerned. We don't want to see what is happening again happen to us a few years ago. But could you just tell us why only 23 were chosen? If it is cost or if it is volatility of the market or just share it with the Committee.

Mr. STEWART. I will take a shot at it.

I think, Mr. Green, that you want to ask that question to the next panel because you have got actual companies with deep water prospects there, but I would speculate with you that at least some of those possible projects are not being developed because they are marginally economic. The reserves that have been found out in the deep water are, in many cases, quite large, but because you lack the infrastructure of pipelines and because it is very difficult—not difficult but expensive—to work in deep water, the economics have to be right.

There are also some risks involved in deep water—geologic risks that don't exist so much in the shallower water where the geology is better understood.

Mr. GREEN. You think if prices would be a little better, those risks would be worth taking?

Mr. STEWART. That is right. You have to have two things in business. You have to have access to resources, and you have to have your economics right. If you get both those right, something will happen.

Mr. GREEN. Let me ask another one.

Again, the concern a lot of us have—and we survived in offshore in Texas for a number of years because we recognized there are risks—but does deep water or frontier area drilling production pose additional environmental risks and does this legislation impact any existing environmental protections or laws or regulations or permits?

Mr. STEWART. I don't believe it does. I think the same technologies that have created or allowed the industry to create the safety record that it has, safety both in terms of human safety and environmental safety in the shallower parts of the Gulf Mexico, those technologies continue to get better. They will be used to the fullest extent no matter what the water depth because it is in our interest to operate safely, not the other way around. And I don't believe there is anything in the legislation that would change that.

Mr. RIGGS. If I could add a point to that.

I think it is worth expanding the focus a little bit and thinking about the environmental impact, to the extent that we are able to find oil through offshore drilling. If we back out imported oil, we are avoiding tankering oil through our waters, and that is where the spills have been coming. So it is an environmental improvement if we find the oil there.

We may find natural gas—and I think we all realize natural gas is an environmentally superior fuel. I believe about 70 percent of what we find in the offshore area is gas.

So there are some revenue questions to be answered on the effectiveness of the bill, but I think environmentally it is not a problem.

Mr. GREEN. I made that argument, too, about natural gas as a legislator, and I am trying to make it now as a freshman in Congress to some of my colleagues here.

One last question if I may, Mr. Fry, and it is good to see you. I know we met last week. And welcome to Washington.

Mr. FRY. Nice to be here.

Mr. GREEN. Has any decision been made on the revised definition of deep water for the purpose of reducing the OCS royalty rates? And should bonding requirements be higher for deep water or frontier area drilling rigs or production facilities? I know—didn't you and I talk last week—there is a lease sale shortly?

Mr. FRY. Yes, and we have now received all the bids. They had to be in by 10 o'clock this morning central time. And I am going to New Orleans after this meeting and will watch my first sale, which will occur tomorrow. As I reported to the Committee earlier, we have 197 bids on 157 tracts, which is an increase over the last two years, or more than double what we had two years ago.

Mr. Green. Great. Are there—have there been discussions about reducing the outer continental shelf royalty rates maybe to encourage production?

Mr. Fry. We have had some discussions about that, and we feel that under existing law, the Department of Interior does have, along with consultation with the Congress, the ability on new leases to do some deep water reductions, or "pre-lease" reductions. We are going to look at that very hard for future sales, to try to encourage additional leasing in the deep water.

You also asked about the bonding. We have just come out with a new bonding rule which did increase the general bonding requirements because we want to make sure the taxpayer is not negatively affected at the end of the lease life with many of these projects. The rule also still allows the Department of Interior to have a great deal of flexibility in terms of those bonding amounts. If we determine that more bonding is required, we have the ability to raise the bonding requirement.

The opposite is also true. If it is determined that the bonding requirement is too steep, based on the risk involved, we have the ability to lower those requirements. So we have a rule in effect, but we also have the ability to look at it on a case-by-case basis, because it certainly is more expensive in the deep offshore to abandon a platform. And so we are going to have to revise our estimates on that, but right now we feel pretty comfortable with our new rule.

Mr. Green. I saw our friend, Bob Armstrong, Saturday when the President was in Houston, and he was on his way back up here, something about a soccer game I think or something. But anyway, thank you, Mr. Chairman.

Mr. Ortiz. Thank you. We have heard some very interesting testimony, and I am sorry that we have been interrupted several times.

At this point, I would like to include the statement of my good friend, Jack Fields, for the record. And hearing no objection, it will be inserted in the record.

[The statement of Mr. Fields follows:]

Statement of Hon. Jack Fields, a U.S. Representative from Texas, and Ranking Minority Member, Committee on Merchant Marine and Fisheries

Mr. Chairman, I want to thank you for scheduling this hearing today, and look forward to hearing testimony on H.R. 1282, the Outer Continental Shelf Enhanced Exploration and Deep Water Incentives Act, that I introduced with several of our colleagues earlier this year.

Mr. Chairman, I appreciate the opportunity you have given us to hear the views of the new Administration and representatives of the oil and gas industry on deep water incentives. I believe that the deep water areas of the Gulf are the future for our OCS oil and gas extraction program. It is important that we encourage and support our domestic industry to make the technological advances that are necessary to explore these deep water areas.

I look forward to hearing input not only on my bill, H.R. 1282, but also on what measures are needed to enable further exploration and development of deep water fields, especially those in the Gulf of Mexico.

Several of our witnesses today will be testifying that the Fields' bill is the first of many steps needed to encourage the production in deep water. I appreciate their candor and hope that this hearing will give the witnesses a chance to tell us what they feel would be necessary to keep our domestic industry interested in staying in U.S. waters.

I hope that the representatives from the Administration will listen carefully to our witnesses, and take these comments back to their respective departments. We need to work hard to make sure that the energy extraction industry in this country does not continue to export jobs to other areas of the world, where they are more welcome than in the U.S.

Thank you, Mr. Chairman. I look forward to hearing the testimony from today's witnesses.

Mr. ORTIZ. That concludes the testimony for this first panel, and I would like to thank both the Federal agencies and NOIA for coming here today and sharing their insights on the legislation. And we can assure you that we would like to work with you and hope that we can implement some type of legislation that would be beneficial, you know, to everybody. Again, thanks for being with us today.

Mr. FRY. Thank you, Mr. Chairman.

Mr. ORTIZ. We can start getting ready for the second panel. I would like now to introduce the second panel which consists of representatives from the oil and gas industry and academia. This panel will present information associated with current deep water and arctic activities, technology and research.

First, we will hear from Mr. Michael Flynn, Manager of the Southeastern Production Division of Exxon Company, U.S.A.. Mr. Flynn will be providing information on current deep water development technologies.

Then we will hear from Mr. Randy Nesvold, Alaska Area Manager for Phillips Petroleum Company. Mr. Nesvold will be presenting information on current arctic development technologies.

Next we will hear from Mr. Phil Wilbourn, Manager of Central Offshore Engineering for Texaco, Incorporated. Mr. Wilbourn will be talking about an industry cooperative program known as Deep Star.

And next will be Dr. Hans Juvkam-Wold, a professor with the Petroleum Engineering School of Texas A&M University, who will be providing a review of deep water and arctic OCS technology and research.

Then we will hear from Mr. Jim O'Sullivan, Manager of Brown & Root Seaflo. Mr. O'Sullivan will provide an overview of the SEAPLAN computer program.

Last, but certainly not least, is Mr. Myron Rodrigue. He is Vice President and General Manager of Aker Gulf Marine, a company that operates two fabrication yards which service the offshore oil and gas industry, particularly deep water projects.

STATEMENT OF MICHAEL E. FLYNN, MANAGER, SOUTHEASTERN PRODUCTION DIVISION, EXXON COMPANY, U.S.A.

Mr. FLYNN. Thank you very much, Mr. Chairman.

My name is Mike Flynn. I manage Exxon U.S.A.'s Southeastern Production Division located in New Orleans, LA. We are responsible for Exxon's producing activities, both on-shore east of Texas and in the Gulf of Mexico. I appreciate the opportunity to discuss incentives to encourage exploration and development in the Deepwater Gulf of Mexico, which I am going to refer to as the Slope in my discussion.

Our division employs 1,500 people directly. Two-thirds of our production comes from the Gulf of Mexico. Our responsibilities include developing opportunities in technologically challenging areas such as the Slope. As indicated by the Department of the Interior, the Gulf of Mexico Slope is thought to contain the largest accessible undiscovered petroleum resource in the nation. Remaining undiscovered resources are estimated to be 4 billion barrels of crude and 44 trillion cubic feet of gas. On an energy equivalent basis, this compares to the 12 billion barrels of liquids in the Prudhoe Bay Field.

The petroleum industry has already discovered 5 billion equivalent barrels in about 90 fields. Half the discovered resource is natural gas. 80 percent of the discovered volumes are believed to be beyond the limit for conventional platforms. Today it is unclear how much exploration and development effort will be focused on the Slope. Only 10 fields containing less than one billion barrels are currently producing or committed to development.

Let me provide some background on the high risks and costs by describing Exxon's activities on the Slope. Our Lena Field, located in 1,000 feet of water, developed 75 million barrels using industry's first guyed tower in 1984. The Lena reservoirs were much more complex than expected. Absent royalty and tax incentives, this field would not be developed today, or it would be developed using a smaller platform and recovering fewer reserves.

Alabaster and Zinc are our most recent developments and we have hosted numerous government officials on visits to that site. Existence of a nearby underwater knoll at Alabaster allowed development with a conventional platform in 470 feet of water. Zinc is in 1,500 feet of water six miles away and was developed with a subsea production system. If not for the fortuitous knoll, development would not have been possible without royalty and tax incentives.

Our next step is a large one because the seven discoveries we have yet to develop are in water depths greater than 2,500 feet. Development costs are high and lead times are long, requiring large investments many years in advance of revenues.

Industry experience is still very limited with the complex geology found on the Slope. In this difficult environment, years are often required for seismic studies, delineation drilling, and careful planning. Single field investments can range between 1 to $2 billion, which is greater than the net assets of all but about 50 U.S. oil and gas companies. Even after an investment is made, sustainable producibility can be uncertain. That was experienced by Placid at its Green Canyon development, which was an economic failure.

In these water depths the threshold size for an economic discovery can vary, but is generally 100 million barrels. We estimate half the volume discovered to date is contained in fields smaller than this, which will require creative approaches. For example, in order to lower costs, several fields may be combined into a single development. Let me further illustrate the challenges faced in deeper water by discussing two currently undeveloped prospects.

The Ram/Powell Field is located in 3,300 feet of water. There are currently no developments in this water depth or beyond worldwide. The three field owners believe total costs, if developed, could be around one billion dollars using a tension leg platform. However, there is still optimization being pursued. There are lower quality reservoirs that we may not develop initially, and possibly not at all, given the current tax and royalty system, as well as risks.

Another field that we have under evaluation is located in 3,000 feet of water in the Green Canyon area. To date only the discovery well has been drilled. One potential development alternative for the prospect is as a satellite to a nearby, existing platform when its production declines. Our ability to take advantage of this type of opportunity is dependent upon flexible lease terms.

Even with added flexibility, royalty and tax incentives are still needed to encourage industry to invest in deepwater projects. Alone, H.R. 1282 would not be sufficient. Additional incentives such as the deepwater production tax credit of $5 per equivalent barrel contained in Senator Breaux's bill are needed to encourage substantial additional activity in the near-term.

Incentives that are nondiscriminatory between producers, structured to reward successful efforts, and apply to new production from existing and new deepwater leases can be effective in the near-term and benefit the Nation as a whole. They are results oriented, encourage investment, create jobs, and government can receive more revenue over time than it potentially gives up.

In closing, I want to say we appreciate the opportunity to present this technology to the Subcommittee. We believe that royalty relief, combined with a production tax credit, together can impact Gulf of Mexico Slope development in a meaningful way. Also working with industry and the MMS, we believe lease term flexibility can continue to be improved to allow efficient, economic resource development. Thank you very much.

[The statement of Mr. Flynn can be found at the end of the hearing.]

Mr. ORTIZ. Thank you.

Mr. Nesvold.

STATEMENT OF RANDY NESVOLD, ALASKA AREA MANAGER, PHILLIPS PETROLEUM COMPANY

Mr. NESVOLD. Thank you, Mr. Chairman.

My name is Randy Nesvold. I am Alaska area manager for Phillips Petroleum Company's North American Exploration and Production Division located in Houston, Texas.

My responsibilities include overseeing Phillips' investments and activities in the Prudhoe Bay and Point Thomson fields in Alaska's North Slope, as well as the recent Sunfish discovery in the Cook Inlet and the Kuuvlum discovery in the Beaufort Sea. I have 12 years of experience with Phillips and have been assigned to Alaska operations for the last 5 years.

Phillips is an integrated oil and gas company that has for the past 76 years been located in Bartlesville, Oklahoma, where it was founded in 1917. We presently employ more than 21,000 people worldwide and we are involved in all aspects of the petroleum business from exploration, production and refining, to transportation, marketing and research.

Phillips has been a leader in opening new frontiers for oil development, including our initial participation in development of the North Slope, and Phillips discovery of the Ekofisk field which opened the door for development of the North Sea. Phillips appreciates the invitation from the Committee to testify on the subject of arctic exploration and production technologies.

First, some background on the Alaska Beaufort Sea. Since the late 1960's, over 60 exploratory wells have been successfully drilled in Beaufort. Unfortunately, due to low oil prices, high operating cost and the harsh operating conditions of the Beaufort Sea, none of the exploratory drilling to date has resulted in discovery of an offshore field that is economic to develop, except for the shallow water Endicott, Point McIntyre and Niakuk fields located adjacent to Prudhoe.

To transform the Beaufort Sea from an exploration play to an economical producing trend, operators will have to overcome environmental, technological and timing challenges presented by the deeper waters of Beaufort Sea. Environmental and technological hurdles can most likely be overcome, but timing is critical. With declining production from existing North Slope fields, the TransAlaskan pipeline and related North Slope infrastructure may become uneconomic to operate as early as 2014.

The Arctic environment poses unique challenges. Operators must contend with temperatures that plunge to minus 65 degrees below zero, two months of total darkness during winter operations, and with the migration patterns of the bowhead whale.

Current technology is well developed to handle arctic exploration. Under the "Drilling" section of my written testimony you will find a series of pictures exhibiting the systems currently capable of operating in the Beaufort Sea, everything from a man-made gravel islands to specially designed ice breaking drilling systems. But the cost of exploration is expensive. Well costs range from a low of $20 million for a spray ice island to over $80 million for a well drilled from a floating drilling system.

Once an offshore field is discovered, options for bringing a field into production are less defined, but initial developments will likely be based on extensions of existing drilling technology.

Several production platform designs have been proposed, and in the "Production" section of the handout you will find conceptual drawings of some of the proposals.

The cost of installing a permanent production facility will be enormous. Estimated development costs are tabulated in the written testimony. The bottom line is that if a major oil field is discovered in the Beaufort, development costs could approach $8 billion or more.

The biggest obstacle facing our operations is not the harsh environment or technological limitations, however. It is timing. Current drilling technology only allows an operator to drill one or possibly two deep water wells per year in the deeper Arctic waters. Once the discovery is made it will take at least nine to 10 years to delineate, design, build and install an offshore facility. It is imperative that major discoveries be made in the Arctic in the very near future in order to take advantage of the existing transatlantic pipeline system and other North Slope infrastructure.

Even with the challenges posed by the offshore Arctic, Phillips is confident new technologies will be developed to meet the challenges just as we were when Phillips first began exploring on the North Slope and in the North Sea.

Thank you, Mr. Chairman, for your invitation to allow us to provide the Subcommittee with information on Arctic technology. We would be happy to address any questions you have.

[The statement of Mr. Nesvold can be found at the end of the hearing.]

Mr. ORTIZ. Thank you.

Mr. Wilbourn.

STATEMENT OF PHIL WILBOURN, MANAGER, CENTRAL OFFSHORE ENGINEERING, TEXACO, INC.

Mr. WILBOURN. Mr. Chairman, I appreciate the opportunity to discuss deepwater technologies with you today.

What I would like to address is the fact that oil today is selling for $20 a barrel. Our assessment of deepwater is that it costs $10 per barrel to get the oil to the refinery. We are talking about the $10 differential. I am talking about in this technology presentation a way of reducing that $10 per barrel lifting cost to in the neighborhood of $8 per barrel, so we can grow this differential. You have heard discussions earlier that address the royalty issue and the tax relief issue.

Specifically I would like to review the Texaco-sponsored DeepStar project. DeepStar is an industrywide cooperative effort focused on identification and development of economically viable, low-risk methods to produce hydrocarbons from deepwater tracks in the Gulf of Mexico.

Presently we have 15 operators as participants and 30 service companies as contributors. Joining together in this industry cooperative effort, progress is being made toward the common goal of having an economic deepwater production strategy and the necessary technology and equipment ready for field use by the latter half of this decade.

The major technology goals for DeepStar include evolving a deepwater concept capable of producing in water depths up to 6,000 feet; accommodation of a broad range of produced fluid properties and rates from various reservoir types; subsea satellite production to host platforms up to 60 miles away; installation of the subsea facilities in a staged manner; remote-operated vehicle installation and maintenance capability; and all production operations remotely controlled from the host platform or potentially in early field life, from the drilling vessel.

The DeepStar concept employs a phased development strategy. It also focuses on a system approach versus a random component design. The three major stages of the development approach are; (1), the exploration and delineation drilling phase; (2), the evaluation and early production phase; and (3), the full field development.

Under the DeepStar concept, initial deepwater subsea production operations will attempt to use existing platforms as host-processing facilities. As confidence in the deepwater concept is established, a staged expansion of the subsea facilities would be initiated. This may require the construction of a new dedicated processing center.

Once established, the center would be capable of handling production from a number of other deepwater prospects within a 60-mile radius. The existence of new deepwater infrastructure will facilitate the commercial development of small fields which would normally not be considered economically attractive on their own.

An opportunity exists here for the industry to again incorporate and establish joint processing centers that can service an entire region. During Phase I of technology studies, the DeepStar team documented and evaluated the capability, cost and availability of basic components and subsystems that would potentially be required for remote subsea development through a series of studies. The results of specific investigations in these areas provided recommendations as to the best types of components for use in deepwater subsea systems to meet an actual field development within the next two to five years.

The Phase II work program for 1993 and 1994 is broken into 10 major technology focus areas. Work in each focus area is overseen by a chairman and a technical committee consisting of representatives from each of the participating companies.

One of the unique aspects of DeepStar is that participants are sharing prior technical research in an effort to "quantum leap" technology development in these key focus areas and to do so at minimum cost.

A number of regulatory-related barriers exist for development of the deepwater Gulf of Mexico. Representatives of the DeepStar participating companies have been meeting on a monthly basis with the MMS to discuss technology issues and current regulations in an effort to identify areas where existing regulations are not in step with technology capabilities.

Areas of discussion have included production monitoring and testing, underwater safety valves, shut down requests, suspension of production, and subsea installation maintenance and repair.

Extended well test operations have also been the subject of numerous discussions. Second only to reservoir questions, produced fluid problems are seen as a major barrier to economically viable production from the deepwater gulf.

Of special concern to the participants is parafin production followed closely by hydrate formation and asphaltine production. Single largest expenditure for deepwater developments will be well drilling and completion cost. This activity alone accounts for between 40 and 70 percent of the cost of deepwater developments.

Cost control and reduction is critical to the effort to make the deepwater gulf commercially viable. The participants are focused on identifying those actions that can be taken to reduce drilling completion and intervention costs.

DeepStar is defining the way operators, suppliers and government agencies can work together to promote development in technically challenging environments such as the deepwater gulf. Many technology issues critical to the progress of deepwater development are being addressed and innovative development concepts and approaches are being evolved.

Thank you.

[The statement of Mr. Wilbourn can be found at the end of the hearing.]

Mr. ORTIZ. Thank you, sir.

Now we can turn to Mr. Juvkam-Wold. You can proceed with your testimony.

STATEMENT OF HANS JUVKAM-WOLD, PROFESSOR, PETROLEUM ENGINEERING DEPARTMENT, TEXAS A&M UNIVERSITY

Mr. JUVKAM-WOLD. Thank you, sir. I would like to talk about the technology and research as it relates to the Outer Continental Shelf and the Arctic. I would like to make my comments in terms of specific problems and solutions.

The main problem we are faced with here is that we consume a lot more oil than we produce. And our consumption is growing and our production is decreasing; in fact, decreasing at the rate of about 3 to 4 percent per year. We make up the difference overall with oil imports to the States, where we are now importing close to half of our crude oil, and our imports account for perhaps two-thirds of our trade balance deficit.

We need to do something about that, but what caused this? What are the reasons for this problem? The problem is that costs, average costs to find, develop and produce hydrocarbons in the U.S. are higher than overseas. These costs are especially high in the deep-water Outer Continental Shelf and in the Arctic.

The proposed solution of providing financial incentives in terms of royalty relief as proposed in this bill I think will help to overcome the difference in cost and will result in somewhat more U.S. oil production. I am not sure it will be enough.

Now to some specific technical problems and solutions. On the Outer Continental Shelf, one of the major problems on the deepwater Outer Continental Shelf is that the cost of production platforms is excessive. Each prospect or project cannot handle the cost of one production platform in deepwater unless the petroleum reserves are very, very large.

Now, one approach to solving this problem is to develop lower cost platforms through the use of new materials and through optimization of size and shape of the platforms and standardization of design. This is the approach taken by the Offshore Technology Research Center jointly operated by Texas A&M University and the University of Texas.

Another approach is to reduce the number of platforms and to place the platforms that you do need in shallower waters. This would require the use of subsea completion and long production lines, and of course is the approach taken by the Texaco DeepStar project we just heard about.

Both these two approaches may be necessary. I want to say that in trying to come up with solutions here, there has been excellent cooperation between industry, academia, and governmental agencies. Perhaps unprecedented cooperation.

Now for a few words about the Arctic. The primary problem, as I see it, in the Arctic offshore is the presence of moving sea ice which results in very high forces on offshore structures. This results in a need for very large, very costly, very heavy structures. So costly, in fact, that only the very largest petroleum deposits would justify development economically.

Now, research efforts are focused in the Arctic on learning more about ice and ice forces. But more research is needed in defining the magnitude of the forces we expect when ice collides with offshore structures.

I have made a short list here of R&D requirements, and this is by no means a complete list, but this is all I am going to have time for. We need, obviously, to be able to install subsea completions in much deeper waters than we have done to date. We are going to need subsea multi-phase pumps, subsea separators. We also need lower cost deepwater production platforms, and of course a lot of work is being done in this area.

We need to learn more about blowout prevention in deep waters. We need lower drilling costs. This is essential. And as far as the Arctic goes, we need to learn more about ice properties and ice forces.

And as a closing comment, I would like to say that the U.S. is in the process of losing its position of leadership in oil field technology primarily because of inadequate long-term research.

Thank you, Mr. Chairman.

[The statement of Mr. Juvkam-Wold can be found at the end of the hearing.]

Mr. ORTIZ. Thank you.

Mr. Sullivan.

STATEMENT OF JIM O'SULLIVAN, MANAGER, BROWN & ROOT SEAFLO

Mr. O'SULLIVAN. Mr. Chairman and Members of the Committee, thank you for the opportunity to appear before you to present information pertinent to your consideration of incentives for oil and gas activities on the Continental Shelf in the United States.

My name is Jim O'Sullivan. I am the manager of Brown & Root Seaflo. Brown & Root has worldwide operations in a broad range of energy services including marine engineering, construction and installation services. The Brown & Root Seaflo unit specializes in offshore field development flange and deepwater production technology.

I have with me today written testimony which is clarifying and more extensive than the document supplied to the staff earlier, and I ask that it be substituted for that earlier document and be entered into the record along with my brief oral testimony.

Mr. ORTIZ. Without objection, it will be included in the record. And I will also say for the other witnesses that might have additional statements, if do you have statements, just give them to the staff and they will appear in the record. Thanks.

Mr. O'SULLIVAN. The written testimony is derived from an in-house study that examined the prospects for deepwater field developments in order to better plan Brown & Root's activities. Let me mention here that the Sea Plant computer program was used in econometrics modeling. I bring that up because you mentioned programming earlier.

The results of the study concur with the observations of the other speakers here today and is presented to the committee as a generalized framework for viewing deepwater Gulf of Mexico developments. I will share with you several brief general conclusions that can be drawn from the study.

Flat oil price forecasts will require deepwater developments to be developed with capital investments below $8 per barrel of recoverable reserves. You have to add the daily operating expenses, which are about $2 to $3 a barrel. That is where you get the $10 number.

To do this, reservoirs will have to perform better than those on the shallower Gulf of Mexico shelf. Wells should produce at or above 3,000 barrels per day and each well should drain between 5 million wells or more. Both these rates exceed typical well performance by around 50 percent, and represents a risk the operator must bear.

The cost of the production facility represents around half the total installed cost of development and offers the most opportunity for cost reductions based on technology advancements. Drilling and completion of wells, transporting the product by pipeline represent roughly about the other half of the installed cost, but are more driven by geological and commercial issues rather than technological ones.

Minimizing surface facilities at the deepwater site offers the best potential cost savings. In general, this involves sharing the processing facilities at one location between two or more field developments and might indicate the need for a regional development approach. This is very similar to the work that DeepStar is pursuing.

A final observation from the study is that technology developments are needed to verify the extension of current technology into deeper water. Cost contingencies are a necessary means for managing technical uncertainties associated with extension of current technology into deeper water.

However, when you apply these contingencies, every 1 percent in projected estimated development cost increases the reserve requirement by 2 percent. So the cost sensitivities are quite an issue. Investments in technology development will reduce the downside uncertainties and improve the overall project economics.

This concludes my brief oral testimony. I hope the written and oral testimony will be of service to this committee in reviewing the need for incentives to develop Gulf of Mexico oil and gas resources.

[The statement of Mr. O'Sullivan can be found at the end of the hearing.]

Mr. ORTIZ. Thank you, sir.

We now have a good friend, Mr. Myron Rodrigue. You can proceed with your testimony.

STATEMENT OF MYRON RODRIGUE, VICE PRESIDENT AND GENERAL MANAGER, AKER GULF MARINE

Mr. RODRIGUE. Thank you, Mr. Chairman. I guess I have to note I am a transplanted Texan.

Good afternoon, Mr. Chairman, Members of the Subcommittee. I appreciate the invitation to testify.

I am Vice President and General Manager of Aker Gulf Marine. We operate two fabrication yards in south Texas, one in Ingleside, one in the Aransas Pass, to service the offshore oil and gas industry.

Our company is a relative newcomer to the industry. In 1984, our parent companies, Peter Kiewit Sons, Inc., investigated the offshore fabrication market and determined the OCS was an area which would experience growth and a need for additional capacity for deepwater platform construction.

Soon after opening our doors in November of 1984, we secured a contract to fabricate Mobil's Green Canyon Block 18 structure, which is now installed in 760 feet of water. At the same time we formed a joint venture to bid Shell's Bullwinkle structure. This joint venture was successful in securing the contract. Fabrication of Bullwinkle, to date the world's largest fixed offshore structure, installed in 1350 feet of water, began in the summer of 1985. This project took three years to build.

Together with the Mobil job and several small other projects we secured, our total employment reached 1,200. If we include subcontractors working directly for us and our clients, total employment at our facilities was over 1600. The point is that deepwater offshore development means jobs for the United States.

I became Vice President and General Manager in December of 1987, just six months before we loaded out the Bullwinkle structure. At that time our total craft employment was down to 200, with no other backlog on the books.

During the first two years as general manager, my priorities were quite diverse. One was to determine the lowest cost option to get out of business. The other was to secure enough work to stay in business.

You can see our business is quite cyclical. It is very difficult to justify the capital investment required to service the deepwater sector of the offshore industry when the market is so unpredictable. This unpredictability is not because our clients are unwilling to explore and develop our offshore resources.

We have invested over $50 million in our plant and equipment. Almost all of that investment came in the first three years of our existence. And because of the unique construction methods required for offshore platforms, we spent a great deal of time and money training a work force capable of producing the quality levels that our clients expect.

Just during 1990, for example, because of the cyclical nature of the business, we spent over $1 million training 200 unskilled workers.

As noted earlier in Mr. Stewart's testimony, our industry has lost 450,000 jobs in the past decade. If you just consider the Bullwinkle project alone, it created an average of over 600 jobs for three years, over a three-year period in south Texas, just for us.

Additional project procurements made in 33 of 50 States added a considerable amount of economic impact to the United States. When you take the expenditures of the indirect suppliers, we undoubtedly impacted the economy of almost every State in the Union.

A predictable OCS development will produce jobs across the United States, not just jobs for coastal States involved in offshore development.

Deepwater development is not only good for reducing our dependence on imported energy, it definitely, without a doubt, is a job-creating and economically stimulating industry.

I might add, in the years I have been in this business, I have noticed that our clients, the major oil companies and all the oil companies have been ahead of their time in recognizing the environmental needs in their development programs.

The petroleum industry can, through this H.R. 1282, as a start, provide our Nation's domestic energy requirements. Producing this domestic energy will strengthen our economy by generating new jobs, allowing the return to work of those trained workers who lost their jobs during the past decade, reducing the flow of dollars to buy foreign energy, and creating additional revenues for the Federal Treasury.

At the same time, it will help President Clinton meet his objectives of increasing the use of natural gas for its environmental benefits.

Thank you for hearing my testimony.

[The statement of Mr. Rodrigue can be found at the end of the hearing.]

Mr. ORTIZ. Thank you very much.

There is no question that we have had some very interesting testimony from you, the witnesses of this panel. I have a question for Mr. Flynn and Mr. Nesvold.

Approximately what percentage of your company's total exploration and development budget goes to foreign projects? Will this legislation help to bring some of this money back to the United States? Maybe you can enlighten members of this Subcommittee.

Mr. NESVOLD. In 1990, approximately 60 percent of Phillips' budget was used on domestic projects. As of 1992, that had dropped to about 40 percent, and basically it is the problem with running out of prospects. Our money is going overseas.

Mr. FLYNN. If you look at Exxon's worldwide spending on capital and exploration, 1992 is about $7.4 billion. About a third of that was spent in the U.S. If you go back about 10 years, it was about $9 billion and a little over half was spent in the U.S.

I think the kind of incentives we have talked about today, both the royalty relief and the tax credit, would do a lot toward helping us progress domestic developments in the deepwater Gulf of Mexico.

Mr. ORTIZ. Mr. Wilbourn, if you would like to give us some insight.

Mr. WILBOURN. Mr. Chairman, within Texaco we are spending in 1993 and projected 1994 somewhere between 55 and 60 percent of our E&P budgets overseas. The thing I think we should realize is there is no shortage of opportunities when you look at what is on our plate today. If you consider the fact that Russia is open, when you consider what is available in China, consider other areas of the world like West Africa and South America, we are not short on opportunities.

Mr. ORTIZ. I have got another question, then I would like to yield to Members of the Committee. This is for Mr. Flynn and Mr. Nesvold.

For your deep Arctic and deepwater exploration and development projects, approximately what percentage of the contracting work is completed by U.S. companies? Will the exploration and development of any new deepwater areas be accomplished through the use of U.S. companies?

Mr. FLYNN. Yes, I think the pattern you heard earlier in the day on projects and domestic spending is exactly right. A large amount of the United States benefits, both directly and indirectly, through service, labor and material contracts. And I don't see any change in that as we move further into deepwater.

I think we want to continue to develop technology domestically. It will help stimulate the economy, create jobs, and that is exactly what we are here today to talk about.

Mr. NESVOLD. Currently in the Arctic it is not as far along as the deepwater. We don't have any major projects currently being developed. The closest thing would be some of the recent expansions at Prudhoe Bay, which were done at New Iberia, Louisiana, and resulted in a substantial increase in the local job market down there.

Mr. WILBOURN. The statement was made earlier that we are losing our edge. I think we see that around the world, where the technology for offshore development is coming from other places other than the U.S., where it has come from in the past. So there is opportunity here.

Mr. ORTIZ. Because I am very concerned that if we provide these incentives and then if we don't create jobs in the United States, then we are going to have some problems. But you do feel there will be jobs created? Great.

I would like to yield to my good friend, Mr. Green, for any questions he might have.

Mr. GREEN. Mr. Chairman, I am going to yield to Congressman Laughlin.

Mr. LAUGHLIN. Thank you. I have got people waiting in my office on some of these very problems.

To follow up on the Chairman's first question, if you went back 10 years—and the gentleman, Mr. Flynn from Exxon, did that—but if your other companies went back 10 years beyond his question, your percentage of expenditure of dollars for whatever your exploration activities would have been would have been even higher here in the United States, I take it, domestically? You need to answer with some oral response. I want it in the record.

Mr. NESVOLD. Yes. I don't have that information right at hand, but it has been steadily declining since 1990, anyway.

Mr. WILBOURN. Within Texaco over the last 10 years we have done a 60/40 flip-flop. We have gone from 60 percent in the United States, and 40 percent overseas, to just about the opposite in 10 years.

Mr. LAUGHLIN. I think Mr. Rodrigue made a very valid point. When you are spending that money domestically, that is circulating around a lot of different businesses. Is that your experience at Exxon and Phillips and Texaco?

Mr. FLYNN. That is very much our experience. I think the study that was referenced by the earlier panel said if a $5 a barrel tax credit by 1998 developed an additional 2 billion to 9 billion barrels, it would create 56,000 to 105,000 jobs. That provides a lot of money moving through the economy to stimulate it.

Mr. LAUGHLIN. Mr. Rodrigue, in the big scheme of things, your company, I take it, is in Aransas County, Aransas Pass?

You are on the wrong side of the county line. You have got smart employees living in the 14th District.

The point you were making about having suppliers in 33 of the 50 States on that one project is a point I think many in the non-oil States of our country lose site of the impact of exploration in oil and gas. In the scheme of things, your company is small compared to Texas or Exxon or Phillips or any of the other what we call majors down there in south Texas, isn't that true?

Mr. RODRIGUE. Yes, sir.

Mr. LAUGHLIN. And here you are doing business in 33 of the 50 States. Now—you are nodding your head.

Mr. RODRIGUE. The things we buy to build the offshore structures come from 33 States. The personnel we use to man the projects comes from the different States.

Mr. LAUGHLIN. Some of those States in that 33 category are States, I assume, that are not considered by most Americans or people living in those States as oil and gas producing States; is that correct?

Mr. RODRIGUE. Yes, sir, that is correct.

Mr. LAUGHLIN. Did any of them ever object to taking your money?

Mr. RODRIGUE. No, they want to know when we are going to pay them.

Mr. LAUGHLIN. Did any of them object to selling you products?

Mr. RODRIGUE. No.

Mr. LAUGHLIN. Even knowing it was going to the oil and gas industry down in south Texas?

Mr. RODRIGUE. No, they tend to solicit our business quite heavily.

Mr. LAUGHLIN. And the point I want to make there is, there are many beneficiaries in all our States to the oil and gas industry; isn't that to your experience, Mr. Rodrigue?

Mr. RODRIGUE. Yes, sir.

Mr. LAUGHLIN. In fact, when people think the oil and gas industry just benefits Texas, Louisiana, and Arkansas, that is an incorrect assumption on their part, isn't that true?

Mr. RODRIGUE. Yes, sir. I mean, Iowa had 21 vendors.

Mr. LAUGHLIN. Iowa?

Mr. RODRIGUE. Iowa, yes, sir.

Mr. LAUGHLIN. And if my lifetime I have never heard anyone suggest Iowa was an oil or gas producing State, have you?

Mr. RODRIGUE. No, sir.

Mr. LAUGHLIN. Have you ever heard anyone suggest that?

Mr. RODRIGUE. No.

Mr. LAUGHLIN. I haven't either. And that is the point that I think is so often lost. And I very much appreciate your testimony. That demonstrates even a State like Iowa that is not thought in the minds of probably anyone in that whole State as being an oil and gas producing State, they have benefited from this industry.

Would you agree with me that if we can get passage of this bill for which the testimony has been offered today that it would benefit people in non-oil and gas producing States?

Mr. RODRIGUE. Yes, sir.

Mr. LAUGHLIN. Even I believe the State of Maine or New Hampshire has no oil wells in it. Would it benefit people in those two States?

Mr. RODRIGUE. In this example I have, Massachusetts had jobs, Connecticut, New York, Pennsylvania, Delaware.

Mr. LAUGHLIN. Pennsylvania is a producing State, as I recall it.

You are a small company and you have done business in these traditional nonproducing States; correct?

Mr. RODRIGUE. Yes, sir.

Mr. LAUGHLIN. Would you, with your south Texas logic, figure that these big companies like Texaco and Phillips and Exxon have done some business with supply companies in these nonproducing States?

Mr. RODRIGUE. I would think so, yes.

Mr. LAUGHLIN. I would, too.

Thank you, Mr. Rodrigue. Your testimony has been about as valuable as any we have had before this Committee in a long time. Appreciate you coming up here representing your employees from Aransas County in the 14th district.

Mr. RODRIGUE. Thank you.

Mr. LAUGHLIN. Mr. Nesvold, I wanted to ask you, you gave and so have others given some testimony about drilling in the Arctic Ocean, and we have had testimony about Russia, and we have had people come by from time to time to talk about the vast oil reserves in the Siberian area and the areas of Alaska where the Russians have even had—I have had people tell me the Russians have had our people come over there, and they don't have a lot of the structures out in the Arctic region of Russia that we have in Alaska. So I want to ask you particularly about Alaska, and anyone else that is got operations there, I don't remember Exxon being there, but if they are, can you nod?

Mr. FLYNN. A partner but we do not operate.

Mr. LAUGHLIN. Maybe you want to fill in, but are the restrictions on the use of Alaskan North Slope wetlands inhibiting development of the Arctic frontier areas?

Mr. Nesvold, if you will answer first, and anyone else operating in that area.

Mr. NESVOLD. We are very concerned about permitting pipelines or drilling pads on the wetlands. Obviously two of our major goals are to; (1) develop oil to reduce our dependence on foreign oil; (2) with a minimum environmental impact. And the best place to do that is where you have opportunities for large oil accumulations with existing infrastructure. And we feel the North Slope of Alaska and Beaufort Sea area is one of those areas, as are any operations in the Gulf of Mexico.

Mr. LAUGHLIN. When you are talking about the Beaufort Sea area and Alaskan North Slope area, we have had before this Committee some controversy about ANWR. Are you talking about going up in the mountains and the meadows of the ANWR area to do this drilling that you are talking about?

Mr. NESVOLD. No, sir. All of our drilling that we have been talking about so far is offshore.

Mr. LAUGHLIN. Out in the water?

Mr. NESVOLD. In the Beaufort Sea. It is not on-shore in the ANWR area.

Mr. LAUGHLIN. The reason I ask that, most of the time when people come in to see me about drilling up there, they want to suggest the drilling is going to be into the interior, some 20, 30, 50 miles interior from the Arctic Ocean and ANWR up in the mountains and the meadowlands. I just wanted to get focused where you are talking about the prospective drilling you are testifying to about today.

Mr. NESVOLD. No, we are talking about offshore North Slope developments.

Mr. LAUGHLIN. People come into my office and represent that Phillips is wanting to do this type of drilling up in the ANWR mountain lands, if they would be misrepresenting your drilling plans at this time; is that——

Mr. NESVOLD. The technology I am testifying on is in regards to offshore drilling.

Mr. LAUGHLIN. Mr. Flynn, do you have any——

Mr. FLYNN. No, I really don't have anything else to offer.

Mr. LAUGHLIN. What happens if the Transalaskan Pipeline System becomes uneconomic to operate and is abandoned before you get an opportunity to bring the Arctic fields into development?

Mr. NESVOLD. It is similar to the response on use of the wetlands. We have to make use of existing infrastructure where it exists next to major reserve potential areas. And probably another good example of the importance of the TAPS line is the McKenzie River delta area over in the Canadian area of the Beaufort Sea which has not been developed, although there have been fields discovered with as high as 300 million barrels in place. But due to lack of infrastructure, it has been uneconomical for Canadians to develop those fields.

Mr. LAUGHLIN. H.R. 1282 proposes various incentives for both deepwater and frontier exploration, which, if either one of those or any of these incentives, would benefit Phillips Petroleum?

Mr. NESVOLD. We only have very small position in water depth, greater than 200 meters. Our primary interest right now is in Arctic explorations. But we would be very interested in broad-based royalty incentives that would provide incentives to develop marginally economic fields.

Mr. LAUGHLIN. That is all the questions I have. Thank you very much, Mr. Chairman.

Mr. ORTIZ. Thank you.

Mr. Green?

Mr. LAUGHLIN. Oh, you know, I did have one other short question. Who is it that is now challenging us for the lead in offshore oil technology?

Mr. JUVKAM-WOLD. Primarily the countries around the North Sea, to some extent also the Brazilians. From the North Sea we are talking about England, Scotland, Norway. France to some extent.

Mr. LAUGHLIN. What is happening to allow them to overtake us? And I guess you could make the comparison to the Japanese overtaking us in the automobile industry. What is allowing these countries of Scotland and England and Norway and Brazil to overtake us in offshore technology?

Mr. JUVKAM-WOLD. Probably the main factor is more funds allotted to R&D. But they have also specific projects that require this new technology and they develop the technology as they need it. And we in the U.S. have been able to supply the technology needs in the world for oil and gas development for many decades, but since we are not developing very much new technology here at this time, they are leapfrogging ahead of us in certain specific areas.

For instance, Brazil has the deepest subsea well completions. And you mentioned Japan. It is my understanding that Japan is currently designing a drill ship to drill in deeper waters than any that we currently have in the U.S. That won't happen for many years, but they are moving into this area also.

So unless we promote R&D in the U.S. to a greater extent and more long-term, I think we are going to be slipping further behind.

Mr. LAUGHLIN. Thank you very much.

Thank you, Mr. Chairman.

Thank you, Mr. Green.

Mr. ORTIZ. Mr. Green.

Mr. GREEN. Thank you, Congressman Laughlin.

Congressman Laughlin's question about the offshore and ANWR—I know that is not what we are here for—there is current production or exploration and hopefully production offshore of ANWR; is that not true?

Mr. NESVOLD. There is exploration in the Camden Bay area, but there is no production offshore ANWR.

Mr. GREEN. What is standing in the way? I understood the ANWR was mainly on-shore issues.

Mr. NESVOLD. Yes, it is. It is totally on-shore. That is why my testimony did not address ANWR whatsoever.

Mr. GREEN. That is why I was wondering. I have had those same folks in our office and we have never talked about offshore, because I thought that was available now and we could do development and exploration and also actual production.

Mr. NESVOLD. Yes. If it was economic, if someone had a large enough find, yes.

Mr. GREEN. But it is not because of government regulations or ANWR or anything else. It is the market that is doing that to us?

Mr. NESVOLD. Yes.

Mr. GREEN. On another side note that Congressman Laughlin brought up—and I know we benefit particularly in Houston, the Offshore Technology Conference every year, it has been a great thing for Houston, I think for Texas, and for the Nation—in the testimony about the development of technology in other parts of the world, particularly the North Sea, will this piece of legislation help us to encourage that particular technology in deep sea exploration?

Mr. JUVKAM-WOLD. I believe so, yes.

Mr. GREEN. The question I asked of the first panel, the one concerning the 175 oil and gas discoveries, our Chairman mentioned in his opening remarks, I asked about it again, that was mainly economics or market. And again I recognize what is happening with the price per barrel as we sit here today. Is that the basic reason why we have only explored or dealt with 23 of those 175 discoveries? And that is for anybody on the panel.

Mr. FLYNN. I think the answer they gave earlier is probably accurate. I don't have detailed knowledge of those particular ones. I will tell you that the slope has unique geologic and economic risk. It is contained in the written and oral testimony that I provided. And the kind of incentives you are talking about today coupled with the tax incentives really hold the promise to help us further develop those areas.

Mr. GREEN. Let me ask Exxon about the Zinc Project as one of those 23 that were chosen. When will it begin? And if you can expound on it and talk about the estimated cost and the number of jobs we are talk about it may create.

Mr. FLYNN. The combined Zinc-Alabaster development cost about half a billion dollars. The Zinc subsea development started up just this last month, and it is currently producing, although we are still completing the drilling operation there. So it is on line, as is the Alabaster host platform.

I don't have with me the detailed breakdown of jobs. We haven't done the analysis that way. I will be glad to look into that and see if we can provide it to your staff.

Mr. GREEN. I appreciate that. The only time I have been to an offshore platform is actually in Alaska in the Cook Inlet. It is almost like the Committee here today, that everybody on the platform spoke like I did. They either pronounced Rodrigue from Louisiana or they had a slow drawl like Congressman Laughlin and I from Texas. So I would be interested to see the impact it would have, particularly in the Gulf Coast area.

Thank you, Mr. Chairman.

I thank the panel. It has been a good panel.

Mr. ORTIZ. Thank you.

I have just one more question. Mr. Rodrigue, I know you built the Bullwinkle. Do you have the technology and expertise—and I believe that you do but I would like to hear it from you for the record—to fabricate the facilities for any deepwater finds in the gulf? And how about the Arctic? Do you believe that the United States is losing the technology in the oil and gas field in that area?

Mr. RODRIGUE. Well, for the gulf, we have the capability to build just about anything that the gulf needs. We have prequalified on some unique and deepwater projects, TLPs, for example. We have prequalified to fabricate hulls, the top sides, the tendons, the foundations of them.

In the Arctic side, we are actually doing some studies and looking at some concepts for concrete structures for some of the finds. They are the real early conceptual designs, but we believe we can do concrete technology that will make some of these Arctic structures viable.

There is a concrete structure being built for the eastern coast of Canada called Hibernia. Our company along with a joint venture partner from Norway who has a lot of concrete technology, bid unsuccessfully on the Hibernia project.

We just received a $125 million project through our parent company to outfit some of the work in Canada. But we would hope we could furnish the expertise for the Arctic from the United States with this new concrete technology, possibly.

Mr. ORTIZ. Very good. I thought that was the last question, but I have one more question for Dr. Juvkam-Wold.

Does this production require any additional environmental safeguards? If so, what are the offshore operators doing to implement these safeguards? Has there been any research completed to address these issues, Doctor?

Mr. JUVKAM-WOLD. There is ongoing research in the safety of drilling offshore. Several universities have programs going on in this area, both from a well-control and a blowout prevention point of view and also from a training point of view. And there are some more complicated problems that we have to deal with as we get into deeper waters. I think we do know how to handle these things, but we need to become more conversant with those technologies.

Mr. RODRIGUE. One comment I would like to elaborate on, talking about the environmental aspect of it, Mr. Fry in his earlier testimony this afternoon mentioned that developing the Gulf of Mexico decreases your reliance on transporting crude by tanker. And I think the offshore oil and gas industries, there is a big misconception in the public's eye about offshore oil and gas versus oil transported on tankers.

Mr. ORTIZ. If I am correct, I think most of the spillage has been not because of the drilling but the transportation. Am I correct?

Mr. RODRIGUE. Yes. There is more oil in the oceans from natural seepage than there is from offshore production. I think there are statistics that prove that out.

Mr. ORTIZ. Very good. Mr. Green, do you have any other questions?

Mr. GREEN. No other questions, Mr. Chairman. I appreciate the testimony. I think it was good. Thank you.

Mr. ORTIZ. I think that this concludes the testimony, unless somebody else would like to add anything else that maybe has been left out.

If not, I really want to thank you for your testimony and the insights you have shared with us today. I think we have heard very interesting testimony this afternoon.

I know there are some other members who cannot attend this hearing this afternoon because they had other obligations. And some of them will be submitting to the panel some questions that we hope you will be able to respond to.

[The information can be found at the end of the hearing.]

Mr. ORTIZ. If there is nothing else, the hearing stands adjourned. Thank you.

[Whereupon, at 4:25 p.m., the Subcommittee was adjourned, and the following was submitted for the record:]

Testimony of

Tom Fry
Director, Minerals Management Service
Department of the Interior

Before the
Committee on Merchant Marine and Fisheries
Subcommittee on Oceanography, Gulf of Mexico,
and the Outer Continental Shelf

U.S. House of Representatives
Washington, D.C.

September 14, 1993

Mr. Chairman and Members of the Committee, I appreciate the opportunity to appear before you today to testify on H.R. 1282, "The Outer Continental Shelf Enhanced Exploration and Deepwater Incentives Act."

Let me preface my comments by saying that the Administration is currently reviewing its OCS policies, including coordinating with the Department of Energy's Domestic Gas and Oil Initiative and here at the Department of the Interior through the Secretary's OCS Advisory Board. Once the review is complete, we will be in a better position to provide more specific comments on OCS issues.

This bill would clarify the discretionary authority given to the Secretary of the Interior under the Outer Continental Shelf Lands Act (OCSLA) to reduce or suspend royalties on existing leases. Second, the legislation adds a new provision to the Act mandating the Secretary to suspend royalties on all new production in water depths greater than 200 meters until capital costs are recovered. Third, Section 18 of the OCSLA would be amended to require the Secretary, when developing an OCS 5 Year Program, to designate as "frontier areas" portions of the OCS, if any, where royalties will be reduced or suspended and the terms of such reduction or suspension.

The Minerals Management Service (MMS) supports the bill's objectives of environmentally sound natural gas and oil investment, production, and employment on the Outer Continental Shelf (OCS). The deepwater portions of these areas represent some of the most promising exploration targets in the United States, but the economic and technological challenges industry confronts in deepwater are substantial and some incentive may be necessary to encourage development.

The MMS has reviewed the bill's provisions with an eye toward striking a balance between ensuring the public a fair return on the value of its OCS resources and providing industry with appropriate financial incentives. To the extent possible, a bill should target benefits projects to that would not be undertaken in the absence of the incentives.

The proposed language in Section 8(a)(3)(A) would clarify the Secretary's authority to grant royalty rate reductions on both producing and non-producing leases in order to "promote development" and "encourage production of marginal...resources." The existing royalty rate reduction authority traditionally has been interpreted to limit the Secretary to considering reductions only on leases that are already in production. The change clarifies the Secretary's authority to design a royalty rate reduction policy on existing leases that could increase the overall economic benefits of development to the Nation.

The Solicitor's office within the Department has advised the MMS that it has the issue of the extent of existing authority to grant royalty rate reductions on non-producing leases under serious study. The Solicitor's office believes that the Secretary might have legal authority to promulgate regulations allowing him (or the MMS) to grant royalty reductions to non-producing leases on a case-by-case basis under certain specified circumstances (or if certain conditions are met) that show that the purposes of the OCSLA would be served. The Solicitor's office emphasizes that this authority can only be implemented through rulemaking, requiring us to publish a proposal and receive and consider public comments on it.

Section 8(a)(3)(B) of the proposed bill mandates that royalties be suspended on leases in water depths of 200 meters or greater until capital costs are recovered. This section has been analyzed in detail because it could have a significant effect on the economics of production in these water depths. It is helpful to consider separately the effect of this section on existing leases and on new leases to be issued in future lease sales.

To estimate the effect on existing leases, the MMS has analyzed 30 discoveries that are large enough to merit consideration for development on non-producing leases in water depths greater than 200 meters in the Central and Western GOM. The MMS results indicate that this proposal would affect the decision on whether to produce on only two of these fields, both located in water depths of greater than 400 meters. These two fields contain an estimated 150 million barrels of oil equivalent.

However, the estimated revenue gains from bringing those two fields into production would be more than offset by royalties forgone from the other fields that would have been produced even in the absence of the incentive. This is estimated to be a net loss of $1.9 billion (in 1993 dollars) in royalty collections. It should be noted that no royalties are expected to be forgone until sometime after 1995, and the total net loss will be spread over the life of the fields. Further, these estimates reflect possible changes in royalty collections only, and these losses should be partially offset by increased tax collections.

For new leases, a mandatory suspension provision could provide benefits to lessees that should lead to increased bonuses for new leases in these water depths, because bidders will bid on more tracts and bid higher amounts when royalty burdens are reduced. MMS estimates that an additional $3-5 million per year in bonuses will be collected from Gulf of Mexico lease sales if this bill is enacted.

In summary, the mandatory royalty suspension provision, as currently written, can be expected to increase bonus revenues to some extent. However, these expected gains would be more than offset by an estimated decrease in royalty collections over the long term. It should be noted that the overall, long-term budgetary impacts are speculative because of uncertainties regarding the amount and timing of development of unleased resources.

As stated previously, we support the objective of the bill, but have not reached a decision regarding the specifics of the legislation. We offer the following as types of changes that, if made, would make it more likely that the Administration could support the royalty suspension provisions of the bill.

- The mandatory suspension should be applied to new leases only. This allows new leases to be issued with more attractive lease terms in deep water to promote activity that can provide substantial economic benefits, stimulate the development of new technology, and provide important natural gas and oil resources for the Nation. However, it also allows the public to benefit from greater bonus receipts in future deepwater lease sales, while avoiding the losses associated with royalty reductions on existing leases that might be produced at current royalty rates.

- The suspension provision should be limited to tracts in 400 meters of water or greater. The analysis mentioned above did not identify any discoveries on existing leases in the 200-400 meter range that would be made profitable by the proposal, and MMS does not expect that offering a royalty suspension on new leases in these water depths will stimulate much additional leasing or development. Furthermore, conventional fixed platforms can be used in water depths out to 400 meters. In deeper waters, new and innovative technologies are required to produce the gas and oil, and an incentive that targets these depths may help develop those technologies.

- Capital costs should be defined to allow the Secretary to set a schedule of allowable costs in regulation, rather than use actual costs. This would greatly simplify the administrative burdens for both MMS and industry and avoid the problem of a larger benefit being given to less efficient (higher-cost) operators.

- The mandatory suspension provision should be limited to tracts in the Central and Western Gulf of Mexico. Most areas outside of these areas are currently under moratoria. The Department believes it should resolve issues concerning new leasing and development in these other areas before providing additional incentives to develop them. Likewise, the designation of "frontier areas" should be limited to areas of the Central and Western Gulf of Mexico until larger policy issues are resolved.

Finally, with regard to proposed changes to Section 18 of the OCSLA, I would note that the Act authorizes the Secretary to propose any system of bid variables, terms and conditions--potentially including a royalty suspension system--that he determines to be useful to accomplish the purposes of the Act when offering leases for sale. Any such system can be implemented if Congress does not disapprove the proposal within 30 days.

Thus, current authority appears to carry out the intent of the proposed change to Section 18 and would be more efficient to implement than the proposed language. Under the proposed language of H.R. 1282, the Secretary would have to define what qualifies as a "frontier area," and a full description of the terms of the incentives must be announced as part of an OCS 5 Year Program. These provisions could restrict the Secretary's flexibility to respond to changing economic conditions because both "frontier areas" and incentive terms would be set perhaps years before they would be used and could not be changed without undergoing a lengthy and cumbersome review, as required by Section 18.

You also requested that I address the various legislative proposals that would offer tax relief for OCS production. Tax law is outside the Department of the Interior's realm of expertise, so MMS analysis may not be adequate for the Subcommittee's purposes. In general, tax credits can provide a more powerful incentive than can royalty suspensions or reductions. Thus, if set at high enough levels, tax credits can both increase the benefits to lessees and increase the costs--relative to royalty relief--of providing incentives for deepwater production.

We would recommend that any legislative proposals offering tax relief for OCS production be consistent with the principles previously discussed with respect to H.R. 1282:

- The incentives should result in increased production of natural gas and oil from the OCS;

- The tax relief should apply only to projects that would not be undertaken in the absence of the incentives; and

- The public should receive a fair return on the value of its OCS resources.

Mr. Chairman, this concludes my prepared testimony. I will be pleased to respond to any questions that the Subcommittee may have.

United States Department of the Interior

TAKE PRIDE IN AMERICA

MINERALS MANAGEMENT SERVICE
WASHINGTON, DC 20240

NOV 29 [illegible]

Honorable Gerry Studds
Chairman, Committee on Merchant Marine
and Fisheries
House of Representatives
Washington, D.C. 20515

Dear Mr. Chairman:

I am pleased to enclose responses to questions submitted by the Committee as a follow-up to the September 14, 1993, Hearing on H.R. 1282, the "Outer Continental Shelf Enhanced Exploration and Deep Water Incentives Act."

Thank you for the opportunity to provide this material to the Committee. If you have any further questions or need additional information, please let us know.

Sincerely,

Tom Fry
Director

Enclosure

cc: Honorable Jack Fields
Honorable Solomon Ortiz
Honorable Curt Weldon

1) How do the short-term revenue losses from royalty relief compare with the potential overall increases to OCS revenues from expanded offshore production and overall benefits in terms of domestic economic growth and job creation?

According to the MMS analysis, H.R. 1282 may possibly generate additional revenues ($3-5 million per year) in the early years due to increased bonus bids on the sale of currently unleased deepwater acreage in upcoming Central and Western Gulf of Mexico OCS lease sales under the royalty suspension terms found in H.R. 1282. This revenue gain is estimated to offset the small reduction in royalties in existing leases over the next several years, since the majority of discoveries in deepwater are not expected to come on line until after 1996.

The MMS analysis of 30 fields large enough to merit consideration for development and located in water depths greater than 200 meters strongly suggests that, over the long term, an across-the-board royalty holiday would provide benefits to about 16 fields that would be developed without the relief. Thus, for these deepwater prospects, there is not necessarily a tradeoff between revenue losses and expanded offshore production with associated economic growth and job creation since much of the job creation is expected to occur anyway.

2) **Has any decision been made on the revised definition of deep water for the purpose of reducing OCS royalty rates? Should bonding requirements be higher for deep water or frontier area drilling rigs or production facilities?**

a. No decision has been made at this time to revise the definition of "deep water" for the purpose of reducing OCS royalty rates.

b. Higher bonding requirements may be utilized in situations where it is evident that lease abandonment costs will be substantial. One example of this situation is exploration and production in deep water or in certain frontier areas where infrastructure requirements are greater than normal. Depending on the particular circumstances, higher requirements are established on a lease-specific basis under the supplemental bonding provisions of the governing regulations.

3) Does deep water or frontier area drilling and production pose any new environmental risks? Does this legislation impact any existing environmental protections, laws, regulations, permits, etc?

a. In general, development and production activities in deep water do not pose any new environmental **risks**. Instead, development and production activities in these areas could pose impacts to environmental resources not encountered elsewhere. For example, chemosynthetic communities have been located in portions of the deepwater Gulf of Mexico (in water depths greater than 400 meters). Chemosynthetic organisms, mainly bacteria, use chemical processes, rather than light, for energy. Platform or pipeline placement and anchoring of support vessels or floating drilling units could potentially impact these communities.

However, a Notice to Lessees requires operators to use geophysical records and photo documentation to identify and protect chemosynthetic communities. Because of this protective measure and the fact that chemosynthetic communities are widespread, any impacts which might occur are expected to be limited, and areas are expected to repopulate quickly. A large number of the several hundred leases in deep water in the Central and Western Gulf of Mexico have been developed without any significant impact to the existing environment.

Frontier area drilling and production could possibly pose some new environmental risks. Risks would be associated with operating in environments that are less familiar and harsher, in some respects, than the established producing areas.

Certain frontier areas also may have environmental resources not encountered elsewhere, such as the endangered bowhead whale offshore Alaska. The bowhead whale, as well as other sensitive environmental resources, have been studied intensively to eliminate or minimize the effects of drilling and production in frontier areas. Also, various stipulations have been recommended for leases issued in Alaska and other frontier areas to help mitigate any expected impacts to environmental resources located in a particular area.

b. The proposed bill, H.R. 1282, does not appear to impact existing environmental protections, laws, regulations, permits, etc.

4) Would the language in Section 8(a)(3)(A), which clarifies the Secretary's authority to grant royalty relief, be helpful in reducing royalty rates on existing leases?

The traditional interpretation of the existing royalty rate reduction authority limits the Secretary to considering only leases that are already in production. The Department's Solicitor's office is studying whether authority exists, through rulemaking, to reduce royalty on non-producing leases. Language in section 8(a)(3)(A) clarifies that authority.

5) What are the cost estimates to the Federal Government for providing various incentives? What impact will these incentives have on the federal budget deficit?

As we stated in our testimony, tax law is outside the Department of the Interior's realm of expertise.

***1) If your suggestions to allow royalty relief only on new leases and only in water deeper than 400 meters were followed, how would this change your budgetary impacts analysis of H.R. 1282?**

If H.R. 1282 were applicable to **both** active and new leases located in water depths greater than 400 meters, we estimate that the total loss of royalty revenues over the life of the projects would be reduced by approximately 15 percent (from $1.9 billion to $1.6 billion). However, if H.R. 1282 was applicable to **new leases only**, no significant budget impacts are expected.

***2) Why does the Department not feel that the increased costs of Arctic development merit royalty relief?**

Currently, Arctic leases are subject to the same lease terms as deep water leases (water depths of 400 meters or more) in the Gulf of Mexico, i.e., longer lease terms and the lower, one-eighth royalty rate.

To date, industry discussions of incentives (such as royalty suspension) have focused on the deep water Gulf of Mexico, so we are looking more closely at that area at this time. In the future, we may also consider whether any such incentives are appropriate in the Arctic. However, the Department has taken no position on incentives for Arctic areas at this time.

***3) If the Secretary of Interior already has the authority to reduce or suspend royalty payments, why has the authority only been used a few times?**

Traditionally, and for some understandable, practical reasons, the Secretary's royalty reduction authority has been interpreted to apply only to leases already in production. Since 1980 (when the first application for royalty relief was received), only 8 applications have requested royalty relief. Of those 8 applications received, 4 were approved; 3 were denied; and 1 is under review.

It also should be noted that drawing the line between when to grant or when to deny royalty relief requests, as well as deciding how much royalty relief to grant, is a complex process. Section 8(a)(3) of the OCS Lands Act allows the Secretary to reduce or eliminate royalty to "promote increased production." However, royalty reduction, in essence, involves changing the terms of a lease, and lease terms can only be changed after compiling a record which clearly sets forth the reasons for granting or denying that change of terms. This process takes time, a rational analysis, and a basis for that action.

***4) How are current deepwater lease holders going to react to a royalty suspension only on new leases? What can we do to encourage production on deepwater leases that at this point are only marginally economic?**

a. The response to your first question is speculative, at best. Some current lease holders may react by developing tracts that are profitable under existing royalty rates. Some lessees may expeditiously relinquish tracts that are not profitable under current royalty rates, allowing the Government to reoffer the tracts potentially at more favorable terms to bidders. Finally, should the Department determine that it has the authority for royalty relief on non-producing leases under current law, or should Congress enact legislation clarifying such authority, lessees holding marginally valued tracts may submit requests for royalty reief on a case-specific basis.

b. Production on deepwater leases which are marginally economic can be encouraged through new legislation that clarifies the authority of the Secretary to provide royalty relief on a case-by-case basis for non-producing leases.

***5) Will the Domestic Gas and Oil Initiative look at incentives such as this bill as well as tax incentives?**

We defer to the Department of Energy for a response to this question.

***6. Do I hear the Administration witnesses leaning toward natural gas production incentives? Are we starting to separate oil and gas production issues?**

Given new requirements in the Clean Air Act Amendments and concern over the impact of emissions on global climate change, a steady and secure supply of clean-burning natural gas is expected to be of increasing importance to the Nation. The Administration is reviewing a wide variety of alternative policies for the OCS program. Although we intend to emphasize production in gas-prone areas of the OCS and to publicize the benefits of natural gas, no definitive decisions have been made at this time on either of your questions.

***7) Why has the Administration urged that this type of initiative be only applied to the Central and Western Gulf of Mexico? Aren't there promising areas other than the Gulf where incentives might make sense (such as the Arctic Ocean)?**

Industry discussions of incentives have focused on the deep water Gulf of Mexico, so we are looking more closely at that area. Also, most areas outside of the Central and Western Gulf are currently under moratoria. The Department believes it should first resolve issues concerning new leasing and development in these other areas before endorsing measures to provide additional incentives to develop them.

In the future, the Department may also consider whether any such incentives are appropriate in other areas, such as the Arctic. Should the Secretary so decide, he has the authority under section 8(a)(1)(H) of the OCS Lands Act to propose any system of bid variables, terms and conditions that he determines to be useful to accomplish the purposes of the Act (including royalty reduction). Any such proposal can be implemented if Congress does not disapprove the proposal within 30 days and after appropriate regulatory changes are promulgated.

***8) Has the tax legislation been scored and if so, how expensive is it estimated to be?**

To the best of our knowledge, none of the tax incentive legislation has been scored.

***9) How do you justify your budget loss projections with the results of a recent DRI/McGraw Hill study which projects gains to the U.S. Treasury?**

The DRI study, conducted for the oil and gas industry, explicitly assumes that a $5 per barrel tax credit, applied to production in water depths beyond 400 meters, would lead to the recovery of all currently discovered deepwater resources of 2 billion barrels of oil equivalents (BOE), plus 7 billion additional undiscovered boe, all of "which would not otherwise be developed." No support for this assumption is provided. The DRI study also measures secondary (multiplier) effects, which presumably would also emerge under any one of a wide variety of policies associated with providing $45 billion in tax credits to selected private companies.

Although the MMS analysis is limited to discovered deepwater resources, it attempts to identify which fields would and would not be developed under tax credits provided by S. 403 and the royalty relief offered by S. 318 and H.R. 1282. Further, the MMS analysis does not count secondary effects.

The MMS analysis estimates that over 1 billion BOE of discovered deepwater resources are currently profitable, and hence worth producing, without any tax credits. We project that the remaining discovered deepwater BOE either will not be profitable to produce even with the tax credits, or will be produced despite having real costs greater than gross revenues. We believe the same arguments would tend to apply to undiscovered deepwater resources as well.

STATEMENT OF

JOHN A. RIGGS

PRINCIPAL DEPUTY ASSISTANT SECRETARY OF ENERGY

OFFICE OF POLICY, PLANNING AND PROGRAM EVALUATION

BEFORE THE

SUBCOMMITTEE ON OCEANOGRAPHY, GULF OF MEXICO, AND THE OUTER CONTINENTAL SHELF

COMMITTEE ON MERCHANT MARINE AND FISHERIES

U. S. HOUSE OF REPRESENTATIVES

SEPTEMBER 14, 1993

Statement of John A. Riggs
Principal Deputy Assistant Secretary of Energy
Policy, Planning and Program Evaluation
before the
House Committee on Merchant Marine and Fisheries
Subcommittee on Oceanography, Gulf of Mexico,
and the Outer Continental Shelf

Good afternoon, Mr. Chairman and members of the Committee. My name is John Riggs, and I am the Principal Deputy Assistant Secretary for Policy, Planning and Program Evaluation at the Department of Energy. It is a pleasure to appear before you to discuss United States policy regarding oil and gas development on the Outer Continental Shelf and to present the Department's views on H.R. 1282, the "Outer Continental Shelf Enhanced Exploration and Deep Water Incentives Act."

The Administration is currently reviewing its OCS policies as part of our Domestic Gas and Oil Initiative and at the Department of the Interior through the Secretary's OCS Advisory Board. Once these reviews are complete we will be in a better position to provide more specific comments on H.R. 1282 and other OCS issues.

H.R. 1282

H.R. 1282 attempts to encourage the production of domestic oil and natural gas resources in deep water on the Outer Continental Shelf by offering royalty relief for new production. It would amend the "Outer Continental Shelf Lands Act" such that any royalty or net profit share set forth in any lease may be reduced or suspended and would require a royalty suspension for new production from any lease located in water depths of 200 meters or greater until the capital costs directly related to such new production have been recovered by the lessee. If, however, the price of oil rises to $28 per barrel or the price of natural gas rises to $3.50 per MMBTU the original lease-stipulated rate would apply.

ROYALTY REDUCTION

I want to discuss three situations regarding royalty suspension or reduction for the deepwater OCS that are also addressed in H.R. 1282: areas that have never been leased or new leases, existing leases that have not gone into production, and existing leases in production.

New Leases: We agree with the Department of the Interior that a royalty suspension on new leases for the early years of the lease until capital costs are recovered could have a significant effect on the economics of production at these water depths. It should be noted, however, that it is uncertain if it would resolve the issue entirely due to uncertainties concerning the amount of proven reserves in deep waters. In addition to increased domestic production, the benefits extend to increased high-wage, high-technology jobs, as well as the development of new, advanced technologies that will maintain the Nation's leadership in offshore technology. These benefits ripple through our economy increasing economic activity, leading to more jobs and revenues.

Existing Leases: Existing leases fall into two categories, those that have not begun production and those already in production.

Pre-production leases: Interior indicates that its Solicitor's office is studying whether Interior can exercise its current discretionary authority to grant royalty reductions to non-producing leases on a case-by-case basis if the royalty reduction can be justified. This approach may satisfy the goal of H.R. 1282--increasing the incentives for deepwater development--without undermining the revenues that could be collected from leases that would have gone into production without any royalty relief. There also may be alternatives to this case-by-case approach that can be explored to determine whether the benefits outweigh the costs associated with royalty relief.

Producing leases: Interior already has the discretionary authority to suspend royalties on a case-by-case basis for those leases that are producing and are not economic. We agree with Interior that no new authority is necessary to accomplish the goal of maintaining production from presently producing properties.

The "Outer Continental Shelf Enhanced Exploration and Deep Water Incentives Act" is a good example of the type of action we are examining with a view to enhancing the viability of our domestic oil and gas industry and increasing domestic production.

DOMESTIC GAS AND OIL INDUSTRY

The U.S. gas and oil industry represents about $300 billion of our Gross Domestic Product or about 5.5 percent of GDP. Just the extraction portion of the industry employs about 380,000 people, while the total industry employs about 1.4 million people. These are high paying, often high-technology, jobs that contribute to the U.S. economy.

Development Costs

Industry exploration and development costs are much higher on the OCS than on land, and they increase significantly with water depth. According to the Joint Association Survey, the cost for the average exploratory onshore oil well is $64 per foot, whereas the cost of the average exploratory offshore oil well is over 6 times that at $392 per foot. In 1991, total costs for the average exploratory natural gas well in the lower 48 states were almost $600,000 onshore and over $5 million offshore. In deep water, a tension leg platform in 3000 feet of water can cost a billion dollars.

Increasing Production

At the same time, we know that some of the OCS areas -- particularly the deepwater Gulf in excess of 400 meters -- are among the most promising. Increasing oil and gas production here in the United States, in an environmentally sound manner, not only increases jobs in oil and gas and their support industries, it also reduces risks of foreign losses and enhances the efficiency of the economy by encouraging technological breakthroughs, reducing oil and gas transportation costs.

Technological Advancement

Doing the technically challenging projects also means assembling cutting-edge scientific talent in oil and gas companies. Because each oil and gas reservoir is different, because each area of exploration is unique, some operations require a new technique.

Deep water drilling allows us to push beyond current producing areas to those places that demand innovative thinking and new solutions. It requires creative minds. The breakthroughs brought on by this demand will benefit our future oil and gas industry. It will also contribute to the retention of the relative advantage we in the United States have in high-tech exploration expertise and spread the use of the best environmental standards to the rest of the world.

CONCLUSION

In conclusion , I would like to thank you again, Mr. Chairman and members of the Committee, for the opportunity to present the Department's views. With an estimated 28 percent of our domestic proven and undiscovered recoverable natural gas reserves, the Outer Continental Shelf is clearly a national asset of great importance for our economy. We support the kind of careful management of our national lands and waters that will offer the greatest benefit to Americans of this generation and the next. It is clearly a tough challenge.

Together, we need to find the best strategy for managing our federal assets -- such as the Outer Continental Shelf -- and the best mechanisms for keeping a strong oil and gas industry in this country. Under the Domestic Gas and Oil Initiative and the Department of the Interior Secretary's OCS Advisory Board we are examining the relative merits of numerous actions, programs and processes that will best govern that nationally owned wealth and -- at the same time -- give us the most efficient and valuable energy sector in the world. The Department looks forward to working with the Committee on these issues.

DEPARTMENT OF ENERGY
Washington, DC 20585
November 15, 1993

The Honorable Solomon P. Ortiz
Chairman
Subcommittee on Oceanography, Gulf of Mexico,
and the Outer Continental Shelf
Committee on Merchant Marine and Fisheries
U.S. House of Representatives
Washington, DC 20515

Dear Mr. Chairman:

On September 14, 1993, John A. Riggs, Principal Deputy Assistant Secretary for Policy, Planning and Program Evaluation, testified before the Subcommittee on Oceanography, Gulf of Mexico, and the Outer Continental Shelf regarding the Outer Continental Shelf Enhanced Exploration and Deep Water Incentives Act (H.R. 1282).

Enclosed are the Department of Energy's answers to the questions submitted by you and Congressman Fields.

If we can be of further assistance, please have your staff contact our Congressional Hearing Coordinator, Lillian Owen, on (202) 586-2031.

Sincerely,

for William J. Taylor, III
Assistant Secretary
Congressional, Intergovernmental
and International Affairs

Enclosures

QUESTIONS FROM REPRESENTATIVE ORTIZ

Domestic Gas and Oil Initiative

Question 1: How does the proposed legislation fit into DOE's National Energy Initiative? Are there other ways to stimulate domestic offshore oil and gas exploration, development, and production?

Answer: The Department of Energy is looking at a range of options to increase oil and gas production. H.R. 1282 -- the "Outer Continental Shelf Enhanced Exploration and Deep Water Incentives Act" -- is similar to options which are being considered. The Administration is examining costs and benefits of various ways to more productively manage nationally-owned assets as well as to stimulate domestic oil and gas exploration, development, and production. Among the options are: plans for cooperative consideration within the Administration of production issues; actions to encourage natural gas regulatory reform; and examination of other limited changes in the tax code.

Incentives such as lower royalties will be considered for the deep water portions of the western and central Gulf of Mexico which would not be developed absent these incentives. In addition, the Department of the Interior will continue to review its leasing policies in mature areas to ensure these policies are appropriate for changing economic conditions and new economic challenges.

The Department of the Interior is committed to working with stakeholders at the state and local level to attempt to resolve issues raised in connection with exploration and development of existing leases. Stakeholders, in some instances, may include local representatives of various Federal agencies.

QUESTIONS FROM REPRESENTATIVE ORTIZ

Domestic Oil and Gas Initiative

Question 2: (a) Does deep water or frontier area drilling and production pose any additional environmental risks?

Answer: The most significant environmental risk associated with deep water drilling is the threat of a pollution incident. The Department of Energy, in agreement with the Department of the Interior, does not anticipate that any qualitatively new type of environmental risks would result from an increase in gas and oil production in the deep water OCS. In fact, an increase in domestic OCS production may provide some environmental benefits by reducing the need for imported oil and the concomitant threat of oil spills associated with international tanker traffic.

It is important to note that over the past two decades, there has been a considerable decline in the number of oil spills originating from offshore facilities in the OCS. The Minerals Management Service reports that the number and total volume of pollution incidents in the Gulf of Mexico OCS has steadily fallen from 183 spills representing a total of 23,125 barrels in 1973, to the most recent report of 25 incidents representing a total of 2,804 barrels in 1992.

This trend can be attributed to significant advancements in offshore gas and oil drilling technology, improvements in spill recovery techniques, and the OCS leasing and permitting program administered by the Minerals Management Service. The Department of Energy believes that this reduction in the number of oil spills further illustrates that gas and oil production from both deep and shallow water regions of the OCS can be accomplished in a safe and responsible manner. It should also be noted that communities in frontier areas have outstanding concerns regarding other environmental impacts associated with OCS development such as drilling discharges, rig emissions, and the onshore industrialization that accompanies off-shore development. It is unlikely that these communities will support new OCS development until these concerns are addressed.

Question 2(b): Does this legislation impact any existing environmental protections, laws, regulations, permits, etc.?

Answer: The Department of Energy does not believe this legislation will adversely affect any existing environmental regulations applicable to OCS gas and oil operations.

QUESTIONS FROM REPRESENTATIVE FIELDS

Domestic Gas and Oil Initiative

Question 5: Will the Domestic Gas and Oil Initiative look at incentives such as this bill as well as tax incentives?

Answer: The Department of Energy will continue to look at a range of options to increase oil and gas production in an economic and environmentally sound manner. H.R. 1282 -- the "Outer Continental Shelf Enhanced Exploration and Deep Water Incentives Act" -- is similar to options which are being considered. The Department is examining costs and benefits of various ways to more productively manage nationally-owned assets, and is exploring changes in the tax code.

Incentives such as lower royalties will be considered for the deep water portions of the western and central Gulf of Mexico which would not be developed absent these incentives. In addition, the Department of the Interior will continue to review its leasing policies in mature areas to ensure these policies are appropriate for changing economic conditions and new economic challenges.

The Department of the Interior is committed to working with stakeholders at the state and local level to attempt to resolve issues raised in connection with exploration and development of existing leases. Stakeholders, in some instances, may include local representatives of various Federal agencies.

Testimony submitted by

Robert B. Stewart

President

National Ocean Industries Association

before the

Oceanography, Gulf of Mexico and OCS Subcommittee

Merchant Marine and Fisheries Committee

September 14, 1993

Good afternoon Mr. Chairman and members of the Subcommittee. Thank you for the opportunity to testify. By way of introduction, NOIA is the only national trade association that represents all facets of the domestic offshore oil and natural gas industry. Our more than 280 corporate members range from major and independent producers to drilling contractors, service and supply companies, manufacturing companies, the telecommunications industry and the financial industry. We are joined in this statement by the International Association of Drilling Contractors, the International Association of Geophysical Contractors and the Petroleum Equipment Suppliers Association.

I appreciate your holding this hearing today and welcome Mr. Fields' efforts to revive our industry through the introduction of this legislation. As you are well aware, our industry has lost more than 450,000 jobs in the past decade, and domestic oil production has fallen below 50 percent of demand. While we currently are experiencing a modest increase in drilling over last year, a greater commitment from the government is needed to stimulate industry activity, halt job losses and improve our domestic oil and gas reserve picture. Enacting production incentives legislation would be a first step down the road to recovery. I will discuss other areas of commitment later in my statement.

NOIA supports the purpose and intent of H.R. 1282, the Outer Continental Shelf Enhanced Exploration and Deep Water Incentives Act. The bill's provisions provide benefits and opportunities to the domestic offshore industry. However, while royalty relief may tip the scales in favor of an otherwise marginal project, additional incentives, such as production tax credits, would be needed to impact substantially near-term activity in the deepwater Gulf of Mexico.

Industry has made technological advances that make development of deepwater oil and natural gas feasible. However, at today's oil and gas prices, many deepwater discoveries are not being developed due to marginal economics resulting from the high costs associated with this unique deepwater setting and the attendant extraordinary economic risks. Up-front costs for deepwater development are extremely high compared to development costs in shallower water. Full field development can exceed $1 billion. Deepwater production experience is fairly limited, the geology is more complex than in more mature offshore areas and a significant use of high-cost three-dimensional seismic surveys is required in addition to more sophisticated drilling and completion tools. An incentives package including production tax credits and royalty relief could result in substantial development in these areas.

As an example of the potential economic stimulation generated by deepwater activity, one of our member companies is developing a prospect from which initial production is anticipated early next year. As of May 1992 more than 900 vendors in 33 states had received contracts on this $1.2 billion project. It is estimated that more than 2,850 people will be employed domestically at one time or another in this project. The impact of this project is even more far-reaching if you consider the next tier of vendors receiving subcontracts from the direct contractors. The number would multiply significantly.

Stimulating new offshore development has significant employment implications. We estimate that for every $1 million invested offshore, 20 jobs are created. And, for every 10 jobs created offshore, 37 jobs are created onshore. There are thousand of workers in need of the jobs that these deepwater incentives would create. Congress has the ability through these types of proposals to put many of these people to work. It is time to create these jobs.

We believe that clarifying the Fields' bill to include incentives for each phase of development could create more projects like the one I just mentioned. Massive up-front costs in many cases dictate the use of multiple phases for development. For example, a small facility would be installed to drill and produce initial production wells to test the reservoir. If the reservoir produces as expected, a permanent facility would be constructed and installed. Additional production facilities may be required if full production cannot be handled by the initial permanent production facility. Each of these phases should be taken into account in considering the nature and extent of incentives to stimulate new exploration and production.

The beneficial impact of the deepwater Gulf of Mexico was recently confirmed by a study sponsored by a group of NOIA members interested in the Gulf of Mexico slope. The DRI study found that incentives that spurred the development of 2 to 7 billion barrels of oil equivalent reserves would by 1998 result in 56,000 to 105,000 new jobs, increase cumulative federal revenues $6 to $10 billion and improve the country's foreign trade balance.

In short, we believe H.R. 1282, together with additional incentives, would help increase domestic energy production, could create thousands of new jobs and generate billions of dollars into the economy.

In addition to Congressional proposals, the Administration can take certain actions that would boost domestic production. For example, as H.R. 1282 would clarify, we believe the Secretary of the Interior has the authority to reduce or suspend royalty payments prospectively - specifically on leases that have been drilled and upon which discoveries have been made, but which are unlikely to be developed because of the small size of the discovery and the resulting marginal economics. We believe that the OCS Lands Act provides the Secretary with this authority, and this authority should be exercised. Section 5(a) of the Act gives the Secretary broad power to "prescribe such rules and regulations as may be necessary" to carry out the Act. Additionally, Section 8(a)(3) of the Act states, "The Secretary may, in order to promote increased production on the lease area, through direct, secondary or tertiary recovery means, reduce or eliminate any royalty or net profit share set forth in the lease for such area." Clearly, if such action is taken by the Administration, at least some of the goals of H.R. 1282 would be met.

One action taken by the Administration that may benefit our domestic energy picture is Secretary O'Leary's Domestic Energy Initiative. As we said in our comments on the Initiative, it is imperative that environmental regulatory costs are balanced by the environmental benefits that result from the requirements. We are anticipating the release of this initiative later this fall.

We also commented to Secretary O'Leary that it appears the government at times works at cross purposes with itself regarding energy policy. One of the problems we face is the lack of reliability of the federal government as a business partner. Congress has placed most of the OCS under leasing moratoria ostensibly so that environmental studies could be performed to determine the effects of offshore development. Then Congress denies funding for the studies since no leasing is scheduled in those areas. In fact, the MMS Environmental Studies Program budget was reduced by 40 percent for FY 94. The National Research Council said last year's funding level, prior to the 40 percent reduction, was barely adequate for MMS to meet its mandate. This looks like a catch-22 to us.

Another problem with reliability is the federal government, through drilling moratoria, has prevented federal lessees from exploring leases that they bought and paid for in good faith. As we have previously testified before this Subcommittee, we believe the federal government should take responsibility for its actions by providing full and prompt compensation to those lessees.

In addition, some of the areas that have been placed under moratoria have a high potential for natural gas discoveries. While we support the Clinton Administration's goal of increasing the demand for natural gas, we have to have new supplies to meet that demand. At present, we are producing at near capacity and have to import some gas from Canada. The Energy Information Agency recently predicted a 26 percent jump in Canadian gas imports, rising to 2.4 trillion cubic feet in 1994. We have the technology and the reserves to accommodate an increase in demand, but are prohibited from doing so by the Congress. Removing disincentives, receiving a solid energy policy from the Administration and enacting incentives legislation would benefit this industry and the nation as a whole with jobs and increased domestic energy production.

In closing, again I appreciate this opportunity to testify today. We are supportive of incentives proposals and offer ourselves to help in any way this Subcommittee feels would be beneficial. I will try to answer any questions you may have.

NATIONAL OCEAN INDUSTRIES ASSOCIATION

1120 G Street, N.W., Suite 900, Washington, D.C. 20005 (202) 347-6900 FAX (202) 347-8650

Robert B. Stewart
President

October 5, 1993

The Honorable Solomon P. Ortiz
Chairman
Subcommittee on Oceanography,
Gulf of Mexico, and the
Outer Continental Shelf
Room 1334
Longworth House Office Building
Washington, D.C 20515-6230

Dear Mr. Chairman:

Once again, please accept my thanks for inviting the National Ocean Industries (NOIA) to present testimony at the Subcommittee's September 14 hearing on incentives for deep water oil and natural gas development. I have received two sets of written questions pertinent to the hearing, on from you on behalf of the Subcommittee and one from Mr. Fields the author of the legislation in question (H.R.1282). Responses to both sets of questions are enclosed. If you have further questions you would like us to address please feel free to contact me.

NOIA looks forward to the opportunity to work with the Subcommittee and its staff to craft legislation that will stimulate investment in OCS oil and natural gas exploration and development.

Sincerely,

Robert B. Stewart

Enclosures

Responses to questions from the hearing on incentives for offshore oil and gas production.

1. Question: What effect will the proposed incentives have on industry's willingness to develop deep water or marginal areas? Response: Companies typically have more potential projects world-wide than they have capital to invest. Companies will choose those projects that are economically the most attractive. The presence of incentives will increase the economic attractiveness of working in U.S. waters and should increase the level of investment in such projects.

2. Question: What can be done to stimulate deep water or marginal areas without legislation? Response: This question would be more appropriate for an operating company than for a trade association. There may be some Secretarial discretion to alter lease terms in ways that would encourage development of these areas.

3. Question: Do you feel that providing royalty relief will induce enough new development, that would not otherwise take place, to make such a proposal justified in terms of protecting federal revenue? Response: I believe it is possible to design an incentives package that will meet that standard.

4. Question: What is your opinion on the proposal presented by MMS to consider royalty relief on a "case-by-case" basis? Response: MMS currently has "case-by-case" authority on producing leases. We believe that authority extends to inducing development of non-producing leases, though that issue is currently under study by the Department of the Interior's Solicitor. One problem with the case-by-case approach is the level of administrative burden on the Department and on the applicant. The burden on the applicant may be great enough to outweigh the economic benefit of royalty relief.

5, Question: Does deep water or frontier area drilling and production pose any additional environmental risks? Response: Existing technology, training and regulations assure that these projects will not pose undue risks to the environment. It can be argued that because these projects are father from shore, the risks are reduced.

6. Question: Does this legislation impact any existing environmental protection, laws, regulations, permits, etc. Response: I do not believe this legislation will have any such impact.

7. Question: MMS has proposed that the Secretary set a schedule of allowable capital costs rather than actual costs. What is your opinion on this proposal? Response: If regulatory simplicity is the object of this proposal, it may well have merit provided it does not diminish the stimulative value of the incentive contained in the legislation.

8. Question: Would this legislation have any impact on unleased tracts in deep water areas within the Gulf, or do you believe that most of the promising areas are already under lease? Response: The impact of this legislation on unleased acreage should be to make it economically more attractive to prospective lessees than at present. By no stretch of the imagination are most of the promising areas of the deep water Gulf of Mexico already under lease. Think of the deep water Gulf of Mexico as a frontier area; lightly explored, little to no infrastructure, complex and not fully understood geology and mostly unleased.

Responses to questions put to industry witnesses from Congressman Jack Fields (R-Texas) Oceanography Subcommittee Hearing, September 14, 1993.

These responses are those of Robert B. Stewart, President of the National Ocean Industries Association. A number of the questions posed by Mr. Fields are appropriate for individual companies but are not answerable by a trade association such as NOIA. We will address those questions we believe we can answer.

1. With respect to the first three questions pertaining to domestic exploration budgets versus exploration spending abroad, we attach a chart showing recent industry trends. Specific data will have to come from individual companies.

2. Question: Are there any areas outside the Gulf where some type of royalty relief should be offered? Response: The only area still open to leasing and development outside the Gulf is offshore Alaska excluding the North Aleutian Basis Planning Area. Consideration should be given to Alaska and such other areas as may become available in the future.

3. Question: If some type of incentive is not available, how cost effective is it to explore Arctic areas? Response: This is a question best answered by companies with experience in arctic exploration and the economics of working in that part of the world.

4. Question: Obviously, the cost of technology to develop deep water areas is high. What other technologies such as air quality controls add significant costs to a development project and should be considered for royalty relief? Response: There are limits to what royalty relief can do to offset costs. It would help if a way could be found to assure that those burdens are sensible scientifically and bear a relationship to the perceived environmental problem.

5. Question: What other incentives should be considered to make deep water development cost effective? Response: Some have suggested that production tax credits coupled with royalty relief would be necessary to spur development in the deeper areas of the Gulf.

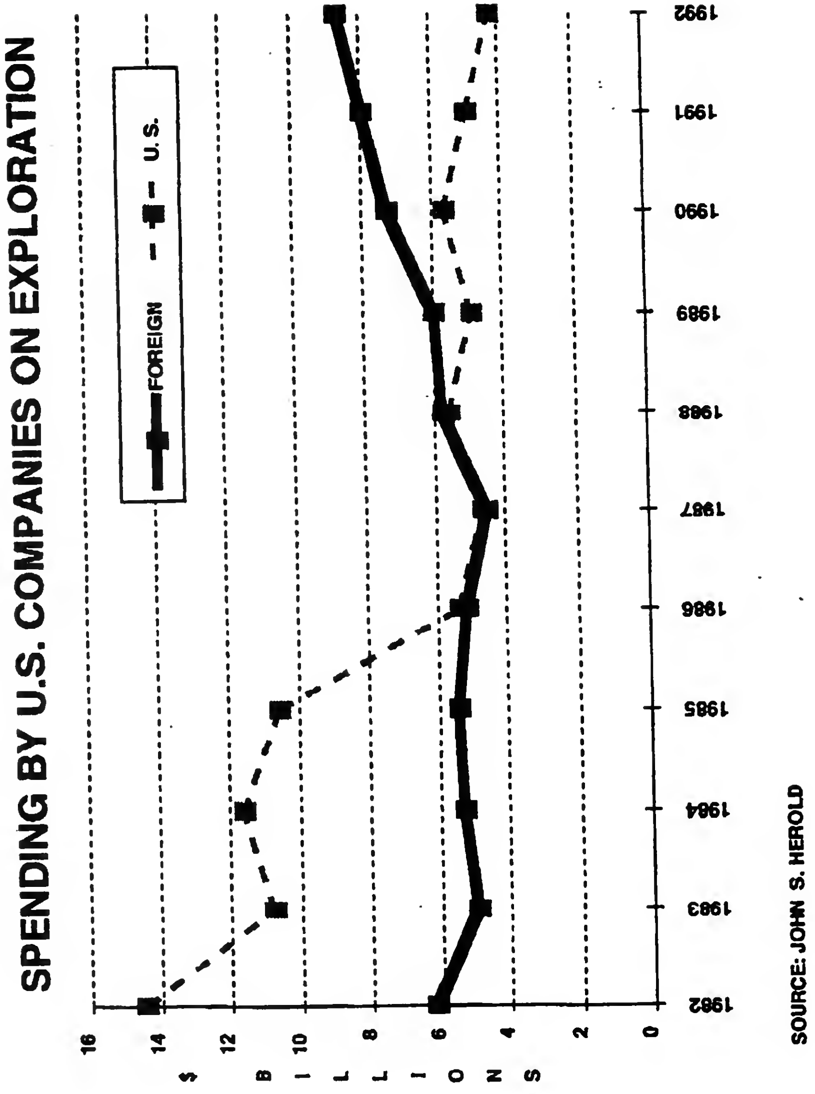
6. Question: Would it influence your lease purchasing decisions to know at the lease sale whether a lease were eligible for royalty relief? Response: This question is better put to a producing company. I would surmise that it might make a difference.

7. Question: In your opinion, does the Secretary have the ability to reduce or suspend royalties and is that authority used? How could that authority be expanded to make it more available? Response: The Secretary clearly has authority under the OCS Lands Act to suspend or reduce royalties on producing leases in order to prevent premature abandonment of production. We also believe that same authority exists in order to promote development of non-producing leases. We understand this question is currently under review in the Solicitor's Office at the Department of the Interior. This authority has rarely been used. In the case of a producing lease we suspect the benefit of royalty relief is overwhelmed by the costs and time necessary to apply for it. The Secretary's authority in the case of non-producing leases could be legislatively clarified. Further, expanded authority such as proposed in Mr. Fields' bill could be extended to enable the Secretary to grant relief on the basis of geologic basins or trends rather than on a tract by tract basis.

8. Question: Would it be more effective if the Secretary could grant royalty suspension of relief before production began? Response: Yes. The earlier in the process, the better and the more broadly geographically, the better.

9. Question: If moratoria continue off the Pacific and Atlantic coasts, what areas are there left for exploration? Response: In this country, the Gulf of Mexico and Alaska excepting the North Aleutian Basin Planning Area. Even the Eastern Gulf of Mexico Planning Area is becoming increasingly controversial.

10. Question: Given our need to offset losses to the U. S. Treasury if OMB and CBO project that the legislation will negatively impact the treasury, what suggestions do you have to bring the cost of this legislation down? Is there anything that can be done to help increase deep water production without directly effecting the budget? Response: If the legislation is designed so that the bulk of the projects receiving incentives are those that would not go forward in the absence of help, then the treasury gains rather than loses. Tax and royalty streams (after capital cost recovery in the case of royalties) would flow to the Treasury in amounts that would not occur in the absence of incentives.


SPENDING BY U.S. COMPANIES ON EXPLORATION
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SOURCE: JOHN S. HEROLD

**WRITTEN TESTIMONY
PRESENTED BY
EXXON COMPANY, U.S.A.
BEFORE THE
SUBCOMMITTEE ON OCEANOGRAPHY, GULF OF MEXICO, AND
THE OUTER CONTINENTAL SHELF
UNITED STATES HOUSE OF REPRESENTATIVES
WASHINGTON, D.C.
SEPTEMBER 14, 1993**

Mr. Chairman, my name is Mike Flynn. I am the Manager of Exxon U.S.A.'s Southeastern Production Division located in New Orleans, Louisiana, which is responsible for Exxon's producing activities, both onshore east of Texas and in the Gulf of Mexico (GOM). I appreciate this opportunity to discuss the GOM and the need for incentives to encourage its exploration and development.

Our Division currently produces 90 thousand barrels of hydrocarbon liquids per day and 750 million cubic feet per day of natural gas. Approximately 65% of this production comes from the offshore GOM. This will increase by 200 million cubic feet per day this year when we begin production from our $1.2 billion, very deep sour gas development in Mobile Bay. We employ 1500 people, operate about 100 offshore platforms, and constitute about 25% of Exxon's domestic production.

Our Division's responsibility is to successfully develop new opportunities in technologically challenging areas such as Mobile Bay and the GOM Slope. The GOM Slope (leases beyond a water depth of 200m (656 feet)) is thought to be the province containing the largest undiscovered petroleum resource in the nation in an area open to exploration and development. The Department of Interior (1991) estimates remaining undiscovered resources of 4.1 billion barrels of crude and 44 trillion cubic feet of gas (totaling nearly 12 billion oil equivalent barrels). This compares to the 12 billion barrels ultimately recoverable from the Prudhoe Bay field which currently provides 18% of U.S. oil production.

These large estimates of remaining potential undiscovered resource for the GOM Slope are supported by results to date. The petroleum industry has under lease from the Minerals Management Service (MMS) 11 million acres and, according to Exxon's estimates, has already discovered 5 billion oil equivalent barrels (OEB) in about 90 fields. Approximately half of the resource discovered to date is natural gas.

Today it is unclear how much exploration effort will be focused on the 12 billion OEB of undiscovered potential or how much of the 5 billion OEB of current discoveries will be developed. Due to unusually high geologic risks combined with high up-front investment requirements and uncertain oil and gas prices, even the largest companies may not be able to justify proceeding at the pace dictated by current MMS leasing terms given today's royalty and tax systems. Nearly 4 billion OEB or 80% of the already discovered volume is in a water depth of 400m (1312 feet) or greater, which is generally beyond the limit for conventional steel-pile jacketed platforms. Consequently, in these deeper water depths, only 10 fields containing less than 1 billion OEB are currently producing or are committed to development. This leaves an already discovered 3 billion OEB as future opportunity.

For additional perspective, I would like to provide some background on these high risks and costs by describing Exxon's GOM Slope activities over the past several years.

Exxon has made a substantial commitment to the GOM Slope and is vitally interested in seeing this commitment benefit both the nation and Exxon. We are the third largest leaseholder in the deepwater GOM with over 1.2 million acres leased. To date we have spent about $3 billion, 30% of this for lease bonuses paid to the Department of Interior. Exxon has drilled 57 prospective accumulations in the GOM Slope and made 11 discoveries with commercial development potential for a success ratio of just 20%. Four of these are developed and on production while seven are under evaluation for possible development.

Our first development was the Lead field (Mississippi Canyon 311) located just at the break point between the Continental Shelf and Slope. This 100 million OEB field was developed using a conventional steel piled jacket and began production almost 15 years ago in 1979. Some of the reservoirs producing in this field have lower quality deepwater rock characteristics. They have proved to be good producing intervals and encouraged further developments.

Our next deepwater GOM development, the Lena field (Mississippi Canyon 281), located in 1000 feet of water, was developed using industry's first guyed tower. This 75 million OEB field came on production in 1984. The tower and original wells cost about $575 million. While the guyed tower cost and performance have been as predicted, the Lena reservoirs were much more complex than initially expected. As a consequence, more producing wells than planned were required to recover the hydrocarbons. In addition, the crude price has been far less than anticipated when the field development decision was made. Hence, if we were faced with the same decision today, absent royalty and tax incentives, the Lena field either would not be developed or would be developed using a smaller platform with fewer wells and recovering fewer reserves.

Alabaster (Mississippi Canyon 397) and Zinc (Mississippi Canyon 354) are our most recent developments. While Alabaster's reservoirs lie under water depths of 1000 to 1500 feet, the existence of a nearby underwater knoll allowed development with a conventional steel piled jacket located in 470 feet of water. Zinc, which is located six miles from Alabaster, is in 1500 feet of water and is being developed with a multiwell subsea production system. Gas and liquid production from Zinc flows by a single pipeline to the nearby Alabaster platform for processing and product disposition. These two gas fields contain about 500 billion cubic feet of natural gas and will require an investment of about $600 million to develop. If it were not for the fortuitous knoll, the economic development of reserves of this size, located in 1500 feet or more of water, would not be possible without royalty and tax incentives. These fields are just now coming on production.

While Exxon has developed four GOM Slope fields in water depths to 1500 feet, our next step will likely be quite substantial. The seven discoveries which we have yet to develop are in water depths ranging from 2500 feet to 4600 feet. Reserve sizes range from about 50 to over 200 million OEB. Due to the water depth, development costs excluding exploration are high, ranging to over $8 per barrel. Also, lead times are long requiring large monetary outlays many years in advance of revenues. In order to successfully develop and produce oil and gas under such conditions, we and other field owners are exploring several development approaches utilizing new and emerging technologies and including multifield development alternatives. Prior to discussing key Exxon opportunities, some background on the broader development issues as we move out into deeper waters may be helpful.

As a result of our experiences and studies, we believe prospective reservoirs underlying the GOM Slope were deposited by currents containing suspended sediments flowing downslope on the ancient ocean floor. Some of these reservoirs have been subjected to complex structuring and salt movement. Industry experience in producing these stratigraphically complex reservoirs is very limited.

In this difficult geologic environment, a significant amount of time, typically several years, is required in the utilization of three-dimensional seismic studies, in delineation drilling and in development planning in order to optimize development and reduce unsuccessful investments.

Conducting a three-dimensional seismic study, considered alone, is a time and people intensive effort for acquisition, processing, interpretation, and reinterpretation as wells are drilled.

Even after a large prospect is adequately delineated, site-specific applications require time to develop. Beyond 400m, development requires production systems (Tension Leg Platform, Floating Production System, Subsea Production System, Compliant Piled Tower) whose technology is proven but evolving quickly. Large facility investments ($500 million range) are required before initiation of production and before reservoir performance information is obtained. Total single field investments can range between $1-2 billion, which is greater than the net assets of all but about 50 U.S. oil and gas companies. With so many systems to evaluate, a fairly long period is expected before an operator would know which technology is most suited for each prospect. Similarly, given industry's limited experience in the deepwater GOM Slope, there is still a relatively high level of uncertainty on the projections of capital and operating costs. History shows that usually cost optimizations can be devised as site-specific designs are considered.

Considering the high initial costs, companies will often need to share infrastructure and facilities by pursuing cooperative, multifield development. For example, stand-alone fields in shallow water may be economic with reserves of 50-60 million OEB. Yet, in water depths just beyond conventional platform technology (>400m), a field size of 100+ million OEB may be required for development at current prices considering the risks involved. In 1000m water depth, this increases to around 200 million OEB. These thresholds can vary depending on the location, relative amounts of oil versus gas, reservoir quality, and other factors such as the availability of existing infrastructure. We estimate that about half the volume discovered to date on the GOM Slope is contained in fields smaller than 100 million OEB and will require creative approaches to enhance attractiveness. Some may become viable as a part of a multifield development.

Producers will need the flexibility to combine fields in order to accumulate economic volumes. However, the relatively small OCS tract size (5760 acres) and typical development requirements that are keyed to individual lease maintenance requirements detract from the industry's ability to capture multifield development synergies. Industry is working on lease flexibility concepts that would recognize the unique nature of the GOM Slope and facilitate optimum paced development. The concepts focus on area-wide development planning, recognizing that geologic and economic interrelationships exist between drilled or undrilled leases in the deepwater setting.

To illustrate some of the challenges being faced in the GOM Slope, I will discuss three of Exxon's currently undeveloped prospects.

The "Ram/Powell" field (Viosca Knoll 912) is located in 3300 feet of water and is believed to contain over 200 million OEB. The field owners, Exxon, Shell and Amoco, are designing a tension leg platform for development. Total costs, if developed, could be around $1 billion. However, there is still optimization being pursued. The development plan being considered includes only the highest quality reservoirs. There are lower quality reservoirs that we may not develop initially and possibly not at all, given the current fiscal system and risks. In planning the development, this "highgrading" is necessary to reduce investment and improve the chances of achieving economic success. Obviously, with lower royalty and federal taxes, more marginal reserves could be pursued.

Another field that we have under evaluation is located in 3000 feet of water in the Green Canyon area. To date only the discovery well has been drilled. We and the other field owner, Shell, will need to drill delineation wells to better understand the size and quality of the reservoirs in this prospect. Such wells can cost over $20 million each. Thereafter, we will be evaluating various development alternatives, one of which is the potential development of this prospect as a satellite to a nearby currently producing platform. This option would be available when existing production declines in the future. Our ability to take advantage of these opportunities when they exist is dependent not only upon site-specific technical and economic considerations, but also on leasehold flexibility provided by the MMS.

The final field I will comment on is "Mickey" (Mississippi Canyon 211), located in 4400 feet of water. It was discovered by Exxon in 1990 by drilling through a 3000 foot salt sill and will also require further delineation. Through new technology in high effort seismic, we were able to image these reservoirs below the salt sill prior to drilling. This was the first deepwater subsalt well drilled by industry and opened up significant new potential for ourselves and the rest of industry.

Even with lease term and administrative changes that allow creation of a viable development opportunity, royalty and tax incentives are still needed to encourage industry to more quickly invest shareholders' money in the high-risk GOM Slope.

We encourage the intent and purpose of HR 1282, the Outer Continental Shelf Enhanced Exploration and Deepwater Incentives Act and appreciate the efforts of the sponsors and this Subcommittee. It recognizes the GOM Slope's large potential resource and the associated high geologic and economic risks in this frontier area. However, while HR 1282 would benefit these deepwater developments, alone this would not be sufficient. Additional incentives such as the deepwater production tax credit of $5/OEB contained in Senator Breaux's proposed bill S.403 are needed to encourage substantial additional development and exploration activity in the near term.

Incentives that are nondiscriminatory between producers, structured to reward successful efforts, and apply to new production from existing and new deepwater leases can be effective in the near term and benefit the nation as a whole. Since they are results oriented and encourage investment, government can receive more revenue over time than it potentially gives up.

A recent economic study, prepared by the consultants, DRI/McGraw-Hill, and sponsored by an industry working group on deepwater GOM incentives, indicates that a $5/OEB production tax credit, such as provided in bill S.403, that spurred the development of 2-9 billion OEB of reserves would by 1998 result in 56,000-105,000 new jobs, increase cumulative federal revenues $6-10 billion, and improve the annual foreign trade balance. Moreover, the study indicated the cumulative federal impact would never be negative. This would hold true because the necessary up-front investment would produce additional corporate taxes before the production tax credit would be allowed.

In closing, I want to say we appreciate the opportunity to present this testimony to the Subcommittee. We are supportive of targeted, results oriented incentives for resources like the GOM Slope that have significant potential to be beneficial to the nation as a whole. We believe that royalty relief combined with a production tax credit, together can impact GOM Slope development in a meaningful way. Also working with industry and the MMS, we believe lease term flexibility can be improved to allow efficient, economic resource development.

PROFESSIONAL BIOGRAPHY
MR. M. E. (MIKE) FLYNN
EXXON COMPANY, U.S.A.
PRODUCTION DEPARTMENT
SOUTHEASTERN DIVISION MANAGER

Mike Flynn began his career in New Orleans, Louisiana in 1973 in the Production Department of Exxon USA after receiving a degree in Mechanical Engineering from Texas A&M University. In 1978, after various engineering and supervisory assignments along the Gulf Coast, he moved to Exxon Production Research Company in Houston where he consulted with Exxon affiliates worldwide. In 1983 he returned to Exxon Company, U.S.A. to manage design of the LaBarge facilities in Wyoming. In 1986 he became the Southwestern Division's Operations Manager in Midland, Texas. He later moved to Houston to become the Crude Oil Manager in the Supply Department and played a major role in establishing Exxon Supply Company in 1989. He went to work for Exxon Corporation in 1990 as an Upstream Advisor. In 1992 he returned to Exxon Company, U.S.A. as a Production Division Manager located in New Orleans, Louisiana. Mike is a member of the Executive Committee of the Mid-Continent Oil and Gas Association (MOGA), Mississippi/Alabama Division and is an Area Vice President of the Louisiana Division of MOGA. He is also on the Board of Directors of Junior Achievement of Greater New Orleans and sits on the New Orleans Business Council.

EXXON COMPANY, U.S.A.
POST OFFICE BOX 61707 • NEW ORLEANS, LOUISIANA 70161-1707

PRODUCTION DEPARTMENT
SOUTHEASTERN DIVISION

October 7, 1993

The Honorable Solomon P. Ortiz, Chairman
Subcommittee on Oceanography, Gulf of Mexico,
and the Outer Continental Shelf
House Committee on Merchant Marine and Fisheries
575 Ford House Office Building
Washington, D. C. 20515

Dear Chairman Ortiz:

I appreciated the opportunity to appear before the Subcommittee to discuss the resource potential in the deeper waters of the Gulf of Mexico and the need for incentives to stimulate exploration and production activity in these areas.

Attached are responses to the written questions submitted by you and Representative Fields. Also attached is my response to Representative Green's question at the hearing about the jobs associated with the Alabaster and Zinc projects.

If you have additional questions, please contact me or Don Smiley, Vice President of Exxon's Washington Office.

Sincerely,

M. E. Flynn

M. E. FLYNN
DIVISION MANAGER

MEF
Attachments

c: w/attachments
The Honorable Jack Fields
The Honorable Gene Green
Mr. D. E. Smiley

EXXON RESPONSES TO QUESTIONS FROM CHAIRMAN OF SUBCOMMITTEE ON OCEANOGRAPHY, GULF OF MEXICO, AND THE OUTER CONTINENTAL SHELF

Q1. What effect will the proposed incentives have on industry's willingness to develop deep water or marginal areas? What can be done to stimulate deep water or marginal areas without legislation?

A1. Exxon believes that targeted incentives, such as the royalty relief contained in H.R. 1282 when coupled with the production tax credit of $5 per oil equivalent barrel contained in S. 403, would encourage substantial additional development and exploration activity in the near term.

While additional lease term flexibility would facilitate optimum-paced development, Exxon believes production incentives are needed to encourage substantial additional development and exploration activity in the near term.

Q2. Approximately what percentage of your company's total exploration and development budget goes to foreign projects? Will this legislation help to bring some of this money back to the U.S.? Will the development of these deep water areas be accomplished through the use of U.S. service companies?

A2. Exxon's capital and exploration expenditures for the upstream (exploration, production and related transportation) totaled $5.2 billion in 1992 of which about two-thirds was for activities outside the United States.

U.S. opportunities stand on their own merit, and Exxon has adequate capital resources for quality opportunities anywhere in the world. Exxon would like to invest in U.S. exploration and production, but most of the attractive prospective acreage in this country is not available for exploration or development.

No one can be certain or guarantee that production incentives will shift exploration and development expenditures to the U.S. because many factors enter into these decisions. However, there are significant, already-discovered resources in the deeper waters of the Gulf of Mexico, and this is thought to be the province containing the largest undiscovered petroleum resource in the U.S. in an area still open to exploration and development. Exxon believes targeted incentives would help encourage substantial additional exploration and development activity in the near term.

Based on past experience, companies, including service companies throughout the U.S., are likely to gain business and therefore benefit from deepwater development. The greatest impact would likely be in the states adjacent to the Gulf.

Q3. Does deep water or frontier area drilling and production require any additional environmental safeguards? If there are any, what are your companies doing to address these safeguards? Has there been any research completed to address this issue?

A3. Exxon believes existing technology is well proven and permits drilling and production in deeper waters in an environmentally safe manner. Existing regulations are adequate to protect the deep water environment.

There has been much research undertaken to enhance our understanding of the physical deep water environment, including water currents, seafloor conditions and topography. The results of this research have been incorporated into the design, construction, placement and operation of deepwater structures.

EXXON RESPONSES TO QUESTIONS FROM THE HONORABLE JACK FIELDS

Q1. How much of your current exploration budget is spent in the U.S.?

A1. Exxon's worldwide exploration expenditures in 1992 totaled $977 million of which $171 million was for U.S. activities.

Q2. How does that compare with ten or fifteen years ago?

A2. Ten years earlier, in 1982, worldwide exploration expenditures totaled $2.6 billion of which $1.5 billion was for U.S. activities. Of the $1.5 billion, $0.4 billion was for lease bonus payments in expectation of much higher energy prices. The remaining $1.1 billion was for activity comparable to the $171 million in 1992.

Q3. If other incentives such as tax credits were offered would that change your decision to go abroad with your exploration budgets?

A3. U.S. opportunities stand on their own merit, and Exxon has adequate capital resources for quality opportunities anywhere in the world. Exxon would like to invest in U.S. exploration and production, but most of the attractive prospective acreage in this country is owned by the federal government and is not available for exploration or development.

No one can be certain or guarantee that production incentives will shift exploration and development expenditures to the U.S. because many factors enter into these decisions. However, there are significant, already-discovered resources in the deeper waters of the Gulf of Mexico, and this is thought to be the province containing the largest undiscovered petroleum resource in the U.S. in an area still open to exploration and development. Exxon believes targeted incentives would help encourage substantial additional exploration and development activity in the near term.

Q4. Are there any areas other than the Gulf where some type of royalty relief should be offered?

A4. Exxon supports incentives to encourage new or the significant expansion of enhanced oil recovery projects. A $5 per oil equivalent barrel tax credit for enhanced oil recovery projects could encourage the development of about 3 billion oil equivalent barrels over 20 years.

Q5. If some type of incentive is not available, how cost effective is it to explore Arctic areas?

A5. A significant impediment to Arctic investment is the lack of access to the Arctic National Wildlife Refuge (ANWR). Exxon believes there is sufficient potential for undiscovered resources in ANWR and other Arctic areas that it would be in the nation's interest for these areas to be explored.

In those high-risk, high-cost areas available for development today, just as in the deep water Gulf of Mexico, targeted incentives, such as royalty relief and tax incentives, would help encourage additional exploration and development activity.

Q6. Obviously the cost of technology to develop deep water areas is high. What other technologies such as air quality controls add significant costs to a development project and should be considered for royalty relief?

A6. Environmental regulations add significantly to the cost of offshore development and, for this reason, should be cost effective and based on scientifically-sound risk assessments. Since oil and gas production facilities in the Gulf of Mexico do not usually generate significant concentrations of air pollutants, existing regulations are adequate to protect the deep water environment.

Q7. What other incentives should be considered to make deep water development cost effective?

A7 Exxon does not believe the royalty relief provisions of H.R. 1282 alone are sufficient to encourage substantial additional development and exploration activity in the deeper water of the Gulf of Mexico in the near term. Additional incentives such as the deep water production tax credit of $5 per oil equivalent barrel contained in S. 403 are needed.

Q8. Would it influence your lease purchasing decisions to know at the lease sale whether a lease were eligible for royalty relief?

A8. Yes. To the extent that royalty relief can be anticipated before the lease sale, one element of uncertainty would be removed. Royalty relief certainly is a step in the right direction. However, as noted in our statement, royalty relief alone would not be sufficient to encourage substantial additional deep water exploration and development.

Q9. In your opinion, does the Secretary have the ability to reduce or suspend royalties and is that authority used? How could that authority be expanded to make it more available?

A9. It is Exxon's opinion that the statutory language gives the Secretary the ability to reduce royalty for future lease sales in order to promote more expeditious exploration of the lease area and also to reduce or even eliminate existing royalty terms in order to promote increased oil and gas production on federal leases where there is existing production.

Experience indicates that MMS has reduced royalties only on a case-by-case basis where premature abandonment of a producing lease would otherwise occur. This happens late in the productive life of the reservoir and thus is not a significant consideration in bringing new reserves into production.

Increasing flexibility to adjust royalties can be accomplished through a more liberal application of the existing law and regulations by MMS. Minor changes to 30 CFR §203.50(b) would be beneficial to clarify the intent that an application for royalty reduction can be initiated at an earlier stage than present practice.

Q10. Would it be more effective if the Secretary could grant royalty suspension or relief <u>before</u> production began?

A10. Yes. Royalty and tax incentives granted before exploration or development begins decreases the reserve size needed to generate an economically successful development and therefore generates additional activity. Incentives granted only after production rates prove a development as economically marginal do not materially stimulate exploration and development activity, although some marginal production could be maintained.

Q11. If moratoria continue off the Pacific and Atlantic coasts what areas are there left for exploration?

A11. Exxon believes the United States should encourage domestic oil and gas production by granting access to all promising OCS and onshore areas, including the Arctic National Wildlife Refuge. Exxon believes exploration and development in these areas can be undertaken in a safe and environmentally responsible manner, would stimulate economic growth, provide jobs and increase local, state and federal revenue.

In the meantime, any expansion of the moratoria areas should be avoided. Inland and the shallow water Gulf of Mexico can still support sizable economic activity. However, they do not hold the potential for large reserves when compared to the deep water in the Gulf of Mexico or to some of the areas under moratoria.

Q12. Given our need to offset losses to the U.S. Treasury if OMB or CBO project that the legislation will negatively impact the treasury, what suggestions do you have to bring the costs of this legislation down? Is there anything which can be done to help increase deep water production without directly affecting the budget?

A12. The targeted incentives supported by Exxon are a good investment because they would encourage economic growth, create new jobs, and increase, not decrease, federal revenues. It is important to remember that the type of incentive supported by Exxon rewards only successful efforts, that is, the incentive becomes available only if the project goes forward and there is actual production. A recent DRI-McGraw Hill study indicates that a $5 per barrel oil equivalent tax credit for new production in the deep water Gulf of Mexico that stimulated the development of 2-9 billion oil equivalent barrels of reserves by 1998 would increase cumulative federal revenues by $6-10 billion.

While additional lease term flexibility would facilitate optimum-paced development, Exxon believes production incentives are needed to encourage substantial additional development and exploration activity in the near term.

EXXON COMPANY, U.S.A.
POST OFFICE BOX 61707 • NEW ORLEANS, LOUISIANA 70161-1707

PRODUCTION DEPARTMENT
SOUTHEASTERN DIVISION

October 7, 1993

The Honorable Gene Green
United States House of Representatives
Washington, D. C. 20515-4329

Dear Representative Green:

I appreciated the opportunity to appear before the Subcommittee to discuss the resource potential in the deeper waters of the Gulf of Mexico and the need for incentives to stimulate exploration and production activity in these areas. At the hearing, you asked about the jobs associated with Exxon's Alabaster and Zinc projects.

The design, fabrication, construction and development drilling for the projects will require an estimated 1,600 job years of labor. (One job year is equivalent to one full-time position for one year.) This includes both Exxon and contractor labor directly related to the projects but does not include indirect jobs created by the manufacture of materials and the expenditure of wages and salaries by those directly employed on the projects. There would also be about 20 direct jobs associated with the ongoing operation of the two fields.

We do not have specific information on the states in which the 1,600 job years will occur but would expect them to be in locations in which major expenditures were made. Payment records indicate that Louisiana and Texas are the primary beneficiaries for drilling and other major contracts. For example, about half of the expenditures thus far for drilling have gone to contractors in Louisiana and half to Texas firms.

We have reviewed the major contracts for platform, template and facilities design, fabrication and construction totaling $155 million and went one step beyond the primary contractor to determine the geographic location of the major work and suppliers. The distribution of the $155 million is as follows: Louisiana and Texas--$67 million each; Pennsylvania--$2 million; Illinois, Georgia and Oklahoma--$1 million each; Massachusetts, Florida, California, Wisconsin and Washington--less than $1 million each; non-U.S.--$14 million (U.K.--$12 million for the electro-hydraulic control system for Zinc; Japan--$2 million for seamless, high strength line pipe). In addition, it is likely that subcontractors purchased material and services from individuals and firms located in still other states, but this information is not readily available.

A DIVISION OF EXXON CORPORATION

The Honorable Gene Green
United States House of Representatives
October 7, 1993
Page Two

Attached for your information are answers to questions submitted after the hearing by Subcommittee Chairman Ortiz and Representative Fields. If you have additional questions, please contact me or Don Smiley, Vice President of Exxon's Washington Office.

Sincerely,

M. E. FLYNN
DIVISION MANAGER

MEF
Attachments

c: w/attachments
The Honorable Jack Fields
The Honorable Solomon P. Ortiz
Mr. D. E. Smiley

TESTIMONY OF

RANDY L. NESVOLD

PHILLIPS PETROLEUM COMPANY

BEFORE THE

SUBCOMMITTEE ON OCEANOGRAPHY, GULF OF MEXICO,

AND THE OUTER CONTINENTAL SHELF

COMMITTEE ON MERCHANT MARINE AND FISHERIES

U.S. HOUSE OF REPRESENTATIVES

SEPTEMBER 14, 1993

OFFSHORE

ARCTIC EXPLORATION & PRODUCTION CHALLENGES

IN THE

ALASKAN BEAUFORT SEA

By: R. L. Nesvold

September 7, 1993

OFFSHORE
ARCTIC EXPLORATION & PRODUCTION CHALLENGES
IN THE ALASKAN BEAUFORT SEA

INTRODUCTION:

Thank you, Mr. Chairman. My name is Randy L. Nesvold. I am the Alaska Area Partnership Operations Manager for Phillips Petroleum Company's North American Exploration and Production Division located in Houston, Texas.

My responsibilities include overseeing Phillips' investments and activities in the Prudhoe Bay and Point Thomson fields on Alaska's North Slope, as well as the recent Sunfish discovery in the Cook Inlet and the Kuvlum discovery in the Beaufort Sea. I have 12 years of experience with Phillips and have been assigned to Alaska operations for five years. My educational background includes a Bachelor of Science Degree in Geological Engineering from the University of North Dakota and a Master of Petroleum Engineering Degree from the University of Houston.

Phillips is an integrated oil company that has, for the past 76 years, been located in Bartlesville, Oklahoma, where it was founded in 1917. We presently employ more than 21,000 people worldwide and are involved in all aspects of the petroleum business from exploration, production and refining, to transportation, marketing and research. We also are substantially involved in natural gas production and liquefaction, chemicals production and sales, and we have been active in other energy areas such as coal, geothermal, nuclear fusion and solar power research. The company's products and processes are used in 33 countries. Our investments have been limited primarily to the energy field.

Phillips appreciates the invitation from the Committee to testify on the subject of arctic exploration and production activities.

BACKGROUND:

Since the late 1960's, over 60 exploratory wells have been successfully drilled on the continental shelf of the Alaskan Beaufort Sea (See Figure M-1). Unfortunately, due to low oil prices, high operating costs and the harsh operating conditions of the Beaufort Sea, none of the exploratory drilling to-date has resulted in discovery of an offshore field that is economic to develop, except for the shallow water Endicott, Pt. McIntyre and Niakuk fields located adjacent to Prudhoe Bay.

Currently, all Alaskan North Slope production comes from onshore fields at Prudhoe Bay, Kuparuk River, Lisburne and Milne Point, and from the shallow water, manmade gravel island of the Endicott field. Two additional offshore fields; Point McIntyre and Niakuk, are also currently being developed. Point McIntyre is being developed from a shallow water gravel island and Niakuk is being drilled with long reach wells from a shore-based drill pad. A map showing the existing North Slope fields is included as Figure M-2.

OFFSHORE ARCTIC EXPLORATION AND PRODUCTION CHALLENGES
September 14, 1993

To transform the Beaufort Sea from an exploration play to an economical producing trend, operators will have to overcome environmental, technological and timing challenges presented by the deeper waters of the Beaufort Sea. Environmental and technological hurdles can most likely be overcome, but timing is the critical variable. With declining production from existing North Slope fields, the TransAlaskan Pipeline (TAPS) and related North Slope infrastructure may become uneconomic to operate as early as 2014. Operators cannot afford to wait for higher oil prices to make Beaufort Sea exploration attractive. New economically viable, as well as environmentally sound technologies, must be developed to deal with the harsh arctic climate. It is crucial this be done soon if new producing fields are to be developed and new production is to be brought on line before the existing North Slope infrastructure and the TAPS are abandoned, especially when you consider approximately 25% of our nation's domestic crude oil production flows through the TAPS line.

ARCTIC ENVIRONMENT:

The arctic environment poses a dual challenge to operators: harsh climate coupled with fragile ecosystems. During summer months, temperatures average 41 degrees F., but during winter months, temperatures average 30 degrees F. below zero with maximum low temperatures dropping to minus 65 degrees F. below zero. Winter operations are also hampered by two months of total darkness (See Figure E-1).

While the weather conditions provide a formidable challenge, the greatest obstacle to Beaufort Sea operations is the arctic ice. For nine months of the year, the entire Beaufort Sea is covered by a sheet of ice. As shown in Figure E-2, the ice is identified by three zones;

1. **LANDFAST ICE** - Ice which forms adjacent to the coastline, extending out to water depths of 50 to 70 feet, where motion is inhibited by the shore. Landfast ice is typically single-year ice and can reach thicknesses of 6 to 7 feet, but may also contain pressure ridges with keels as deep as 70 feet.

2. **POLAR ICE CAP** - This is permanent multiyear ice which circulates clockwise in the northern Beaufort Sea and central arctic basin. The rotating ice cap is referred to as the Beaufort Gyre and is shown on Figure E-3. The average ice thickness in the polar ice cap is only 9 to 12 feet, but large pressure ridges may extend to depths of 150 feet or more.

3. **TRANSITION ZONE** - This is the area located between the Polar Ice Cap and Landfast ice. The transition zone may be tens to thousands of miles wide and generally contains first year ice, but may also contain concentrations of multiyear ice.

During the month of May, the Landfast ice zones begin to breakup and by July, an ice-free, open water corridor exists along the coastline. This ice-free zone lasts until new ice begins forming in October. During the open water season, multiyear ice islands that break away from the polar ice cap and drift through the open water areas can cause significant operational problems. Ranging up to 150 feet thick, these multiyear ice floes cause severe ice loading problems for permanent structures.

Ice scours, caused by the keels of pressure ridges and multiyear ice floes, can also cause a major problem for subsea pipelines. Most of the Beaufort Sea research on ice scouring to-date indicates scours achieve a maximum depth of 15 feet. (A conceptual drawing of an ice scour in relation to subsea pipelines is shown on Figure E-4.)

In addition to the severe arctic climate, operators in the Beaufort Sea must also address unique environmental issues. For example, the Beaufort Sea is the migratory route for the Bowhead whales and the Native Eskimo villages of the North Slope still rely on the Bowhead whale for their subsistence. Operators, in conjunction with the National Marine Fisheries Service (NMFS), the Minerals Management Service (MMS) and the North Slope Borough, have monitored whale migration patterns since the late 1970s. The data obtained allows operators to determine if drilling and seismic operations have an impact on whale migration patterns. Ultimately, the data acquired provides a basis for structuring drilling and seismic operations in such a manner as to minimize the impact on the whale migration, and in turn, minimize the impact on the Eskimo whaling communities.

Environmental compliance can be very costly. A good example of the economic implications of environmental concerns is the installation of a 650 foot breach in the Endicott causeway.

Built to alleviate concerns over the impact that the causeway might have on fish migration patterns, the Endicott owners constructed this 650 foot breach at a cost exceeding $65 million.

EXPLORATION DRILLING TECHNOLOGY:

Current arctic exploration technology is well developed. A fleet of drilling systems is currently available for arctic exploration. A brief discussion of current arctic exploration technology that is available to the industry follows:

1. **GRAVEL OR EARTHEN ISLANDS** - The first arctic offshore wells were drilled from gravel islands in 1973. Artificial islands provide a year-round drilling platform and can be used in water depths of up to 50 feet, but are generally not economical in water depths greater than 10 feet. (Figure D-1 is a picture of Shell's Seal Island well which was drilled from a gravel island.)

2. **CAISSON RETAINED ISLANDS (CRIs)** - CRIs were developed to minimize dredging requirements. The caisson retained island consists of a ring of caissons, stressed together with cables and filled with sand to form a drilling platform. CRIs have been used in water depths of up to 70 feet and are capable of operating in up to 100 feet of water.

3. **SPRAY ICE ISLANDS** (Figure D-2) - Ice islands are created by spraying seawater on existing ice to create an ice sheet thick enough to ground on the sea bed, forming a stable

platform for exploration drilling or support activity. Application of ice islands is currently limited to water depths between 10 to 40 feet within the Landfast ice zones and drilling time is limited to 105 days. The biggest advantage of ice islands over gravel islands is the cost of construction. Based on 1985 estimates, ice islands cost $300,000 per foot of water depth versus $1,500,000 per foot of water depth for a gravel island.

4. <u>BOTTOM FOUNDED DRILLING SYSTEMS</u> - Three bottom founded mobile drilling systems currently exist for arctic exploration. Bottom founded drilling platforms are capable of working in water depths of up to 80 feet and allow for year-round drilling. (Pictures are attached for the Canmar SSDC/Mat (Figure D-3), the Glomar Beaufort Sea I - CIDS (Figure D-4 and D-5), and the Beaudril Molikpaq (Figure D-6).)

5. <u>DRILL SHIPS</u> (Figure D-7) - Drill ships can operate in water depths ranging from 50 to 1000 feet, but have a very restricted drilling season. Drill ships can only operate in open water or in partial ice cover when supported by icebreakers. As a result of ice limitations, drill ships are generally limited to operating from mid-July to early November. When downtime for severe ice conditions is included, drillships are limited to an average of 50 to 60 drilling days per year.

6. <u>PURPOSE BUILT FLOATING DRILLING PLATFORMS</u> (Figure D-8) - The purpose built Beaudril Kulluk floating rig was specifically designed to operate in water

depths comparable to drillships, but in more severe ice conditions. The Kulluk was designed to operate year-round in Landfast ice conditions up to 4 to 6 feet thick, but in the transition ice zones of the Beaufort Sea, the Kulluk is limited to the same drilling season as drill ships, but with much less downtime due to ice conditions. The Kulluk is expected to average 100 to 110 drilling days each year.

EXPLORATION COSTS:

Limited public data is available on the cost of exploration wells, but depending on water and well depths, estimated drilling costs range from 20 to 80 million dollars per well. Shallow water spray ice islands would be the lowest cost wells, while wells drilled from floating drilling systems are the most expensive.

PRODUCTION TECHNOLOGY:

Once an offshore field is discovered, options for bringing a field into production are less defined. Initial developments would likely be based on existing technology, utilizing experience gained from arctic exploration drilling systems. Currently, the only existing offshore arctic production is from the manmade gravel islands at the Endicott field (See Figure P-1). The 400 million barrel Endicott field began production in October of 1987 and established a peak production rate of 100,000 barrels of oil per day in 1987. Endicott is located northeast of Prudhoe Bay and is connected to the mainland by a 5-mile causeway. The total cost to install the gravel islands and place the field on line was slightly over $1 billion.

Gravel island technology, however, is limited to water depths of 10 feet or less and virtually all other proposed deep water production schemes are still in the conceptual stage. Several production platform designs have been evaluated and determined to be feasible with today's technology. Examples include:

1. <u>STEEL GRAVITY STRUCTURES</u> (Figure P-2) - A steel gravity drilling and production platform would be constructed using existing construction techniques and dry dock facilities, and transported to the arctic for final installation. A typical platform might have a deck area of 125,000 square feet at each of two levels, with a structural weight of 85,000 tons. The platform could support two drilling rigs and would have a storage capacity large enough to operate for 270 days without resupply.

2. <u>CONCRETE GRAVITY STRUCTURES</u> (Figure P-3) - Concrete gravity structures would be fabricated using existing North Sea concrete construction techniques and would weigh approximately 350,000 tons. Surface areas and capacities would be similar to the steel gravity platform.

3. <u>CONCRETE MONOCONES</u> (Figure P-4) - The wide base and narrow, single shaft tower of the concrete monocones are designed to minimize ice loads.

4. <u>CONCRETE ISLAND STRUCTURES</u> - Concrete island structures are a modification of Global Marine's CIDS (concrete island drilling system) which has operated in the arctic. The system consists of a steel base with a concrete tower extending through the ice zone and steel topsides.

5. <u>STEEL CAISSON STRUCTURES</u> - A steel caisson structure would be constructed of a circular caisson shell with a sand-filled core. This type of structure has a limited bulk storage capacity in comparison to a steel or concrete gravity structure.

6. <u>CONCRETE CAISSON RETAINED ISLANDS</u> - A caisson retained island would be constructed of pre-cast cellular, concrete caisson, which would act as a retaining structure for a sand/gravel island. Construction costs for this type of structure are less than for a platform, but the savings are offset by longer installation times and higher installation costs.

7. <u>PIPELINES</u> - Transportation of oil would almost certainly be via a subsea offshore pipeline to the TransAlaskan Pipeline Pump Station #1 at Prudhoe Bay. Although no subsea pipelines have been installed in the Beaufort Sea, detailed studies have indicated that installation is feasible using current technology and equipment. Pipelines would be trenched and buried to depths as required to protect the lines from ice scour. Onshore

pipelines with associated pump stations would be constructed using above ground supported pipe similar to the existing Prudhoe Bay and TAPS pipelines. In permafrost zones, pipelines would be insulated to protect the permafrost from the effects of heat dissipation.

DEVELOPMENT COSTS:

The Alaska Oil and Gas Association (AOGA) has completed extensive research on the costs to explore and develop offshore fields. Costs for various components of developing a prospect are as follows:

COMPONENT	COST	
Platform Structures		
Shallow water (<50 ft)	\$200 to 300	Million/Platform
Deep Water (> 50 ft)	\$350 to 450	Million/Platform
Processing Facilities	\$300 to 600	Million/Facility
Onshore Supply Base	\$100 to 200	Million
Well Drilling Cost	\$ 4 to 5	Million/Well
Pipelines		
Subsea (18 to 24 inches)	\$ 3 to 4.5	Million/Mile
Onshore (30 to 36 inches)	\$ 6 to 8	Million/Mile

Depending upon the size of the accumulation, the number of platforms required, the number of wells required and the distance from the TransAlaskan Pipeline, the cost of development can vary greatly. Published data on the undeveloped Northstar and Sandpiper fields located in shallow water near Prudhoe Bay, indicated development costs for these fields range from $860 million to over $1.4 billion. Development of a major deep water field, at greater distances from Prudhoe Bay, could approach $8 billion or more.

TIMING:

The biggest obstacle facing arctic operators is not the harsh environment or technological limitations, it's timing. With existing North Slope production declining, it is only a matter of time before TAPS and the existing Alaskan North Slope infrastructure are forced to be abandoned due to a lack of economic viability. According to a recent Department of Energy (DOE) study of proven and probable North Slope production, TAPS is expected to reach its economic limit as early as 2014. (A forecast of the DOE North Slope Production Forecast is shown on Figure T-1.)

Although advances in technology or changing economic conditions may extend the life of TAPS past 2014, this is still a very disturbing statistic. When you consider the fact that current drilling technology only allows one or possibly two deep water wells to be drilled per year and once a discovery is made, it will take at least 9 to 10 years to delineate, design, build and install an offshore production facility, major discoveries will have to be made in the very near future to make an impact on the economic life of TAPS. (A typical installation schedule is shown on Figure T-2.)

If a major field, either onshore or offshore is not discovered before the end of the decade, it may be too late to save the TAPS pipeline. The best example of the importance of the TAPS pipeline and North Slope infrastructure is the lack of development of the Amauligak field in the Canadian Beaufort Sea. Even with an estimated recoverable reserve of 300 to 400 million barrels with production potentials of 50,000 barrels of oil per day per well, the field has been uneconomical to develop due to the lack of a pipeline or an existing infrastructure.

Thank you, Mr. Chairman, for your invitation to allow us to provide the Subcommittee with information on arctic technology. I would be happy to answer any questions you may have.

REFERENCES:

1. Brian Watt Associates, Inc., "Feasibility and Costs of Exploration and Production Systems in OCS Lease Sale 87, Diapir Field, Alaska", AOGA Project 233, February, 1984.

2. Charles Thomas, et al, "Alaska North Slope National Energy Strategy Initiative, Analysis of Five Undeveloped Fields", U.S. Department of Energy, May, 1993.

3. M. Rojansky, "Arctic Exploration and Production Structures", MTS Journal, Volume 18, Number 1.

4. B. Danielewicz, "A Short Summary of the Physical Environment of the Beaufort Sea and Its Effect on Offshore Operations", September, 1983.

5. "Man-made Ice for Construction in the Arctic", Alaskan Update, Volume 4, Number 2, Spring, 1986.

6. D. Masterson, J. Bruce, R. Sisodiya and W. Maddock, "Beaufort Sea Exploration: Past and Future", OTC 6530, May, 1991.

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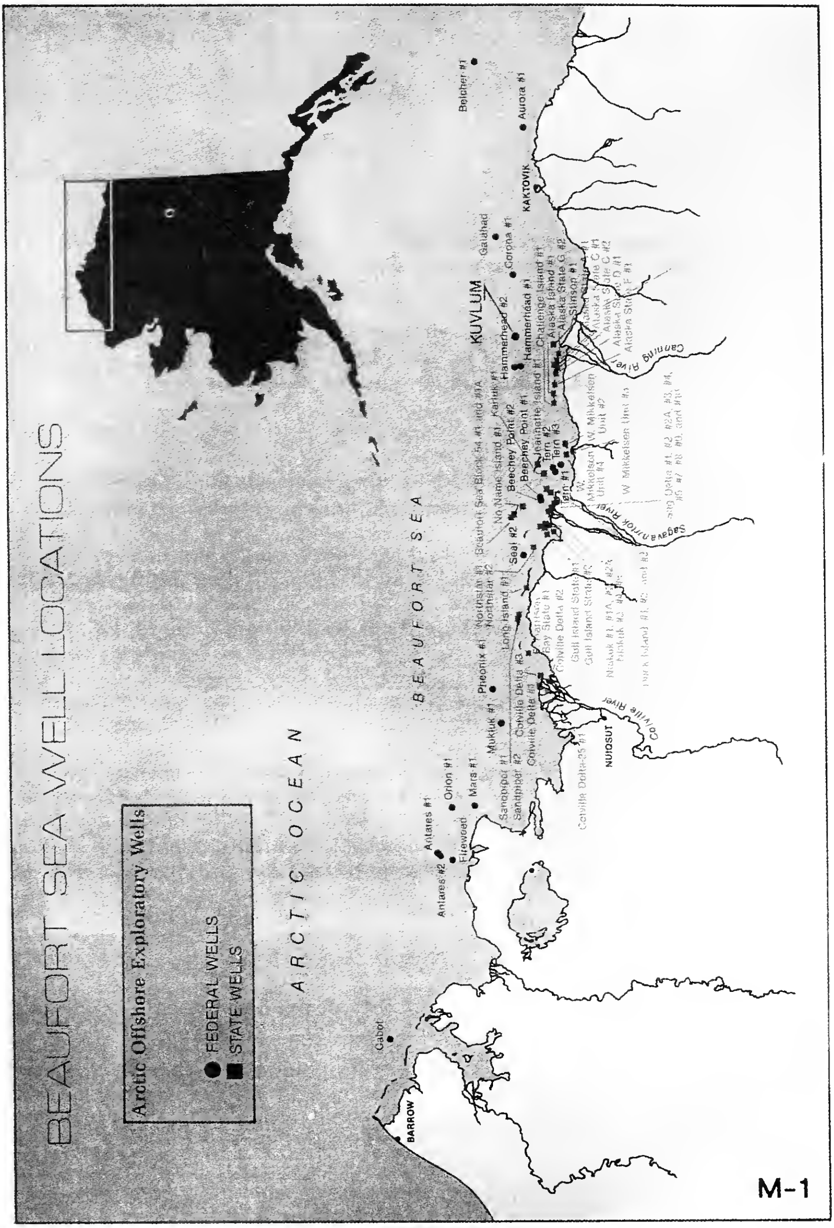
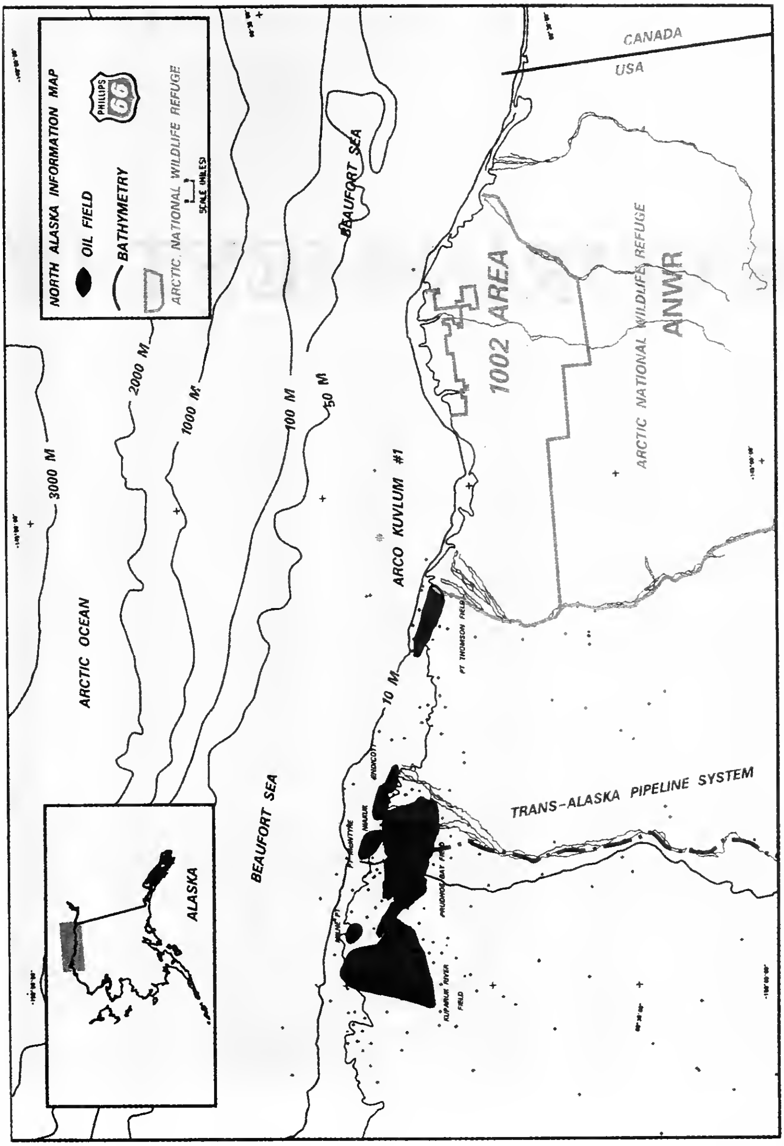
8. W. Timmermans, "Design, Installation and Operation Described for Beaufort Sea Pipelines", O&G Journal, May 10, 1982.

9. M. E. Enachescu, "Structural Setting and Validation of Direct Hydrocarbon Indicators for Amauligak Oil Field, Canadian Beaufort Sea", AAPG, January, 1990.

10. "Arctic Offshore Exploratory Wells", Alaskan Update, Volume 9, Number 4, Winter, 1991/1992.

MAPS (M)


BEAUFORT SEA WELL LOCATIONS
Arctic Offshore Exploratory Wells
FEDERAL WELLS
STATE WELLS
ARCTIC OCEAN
BEAUFORT SEA
BARROW
Cabot
Antares #1
Antares #2
Fireweed
Orion #1
Mars #1
Mukluk #1
Pheonix #1
Sandpiper #1
Sandpiper #2
Colville Delta #3
Colville Delta #1
Long Island #1
Northstar #1
Northstar #2
Seal #2
Beaufort Sea Block 54 #1 and #1A
No Name Island #1
Karluk #1
Beechey Point #2
Beechey Point #1
Jeannette Island #1
Tern #1
Tern #2
Tern #3
Hammerhead #2
Hammerhead #1
Challenge Island #1
Alaska Island #1
Alaska State G #2
Stinson #1
KUVLUM
Galahad
Corona #1
KAKTOVIK
Aurora #1
Belcher #1
NUIQSUT
Colville River
Sagavanirktok River
Canning River
W. Mikkelsen Unit #4
W. Mikkelsen Unit #2
W. Mikkelsen Unit #3
M-1

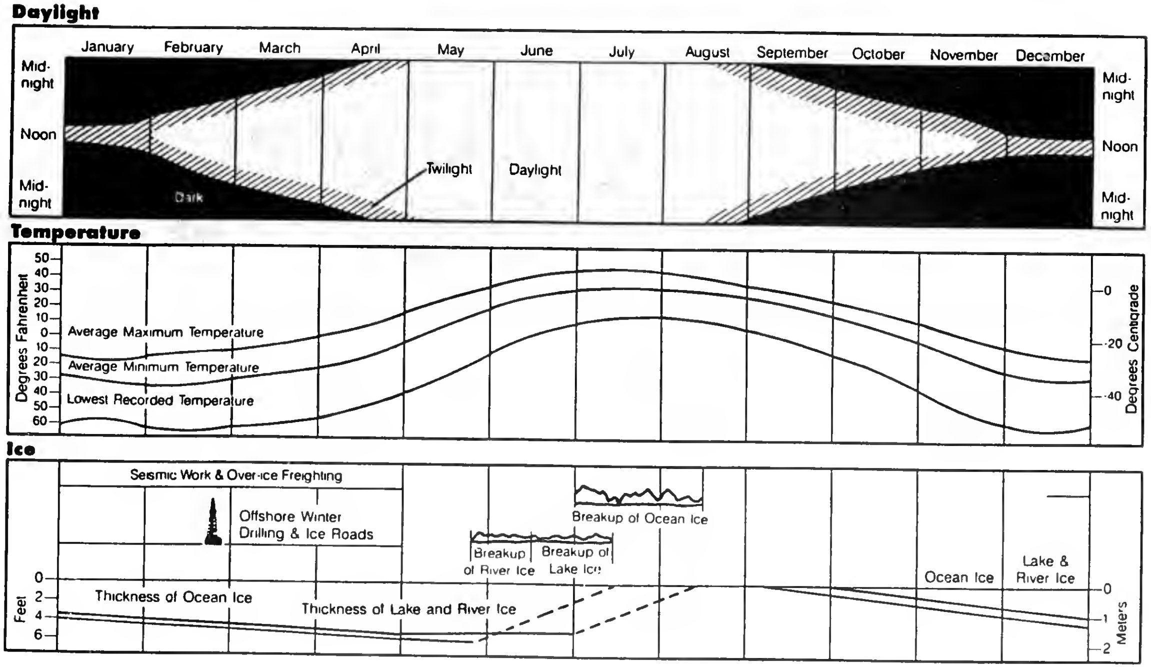


NORTH ALASKA INFORMATION MAP
PHILLIPS 66
OIL FIELD
BATHYMETRY
ARCTIC NATIONAL WILDLIFE REFUGE
CANADA
USA
BEAUFORT SEA
ARCTIC OCEAN
3000 M
2000 M
1000 M
100 M
50 M
10 M
ARCO KUVLUM #1
1002 AREA
ARCTIC NATIONAL WILDLIFE REFUGE
ANWR
PT THOMSON FIELD
ENDICOTT
NIAKUK
PRUDHOE BAY FIELD
KUPARUK RIVER FIELD
TRANS-ALASKA PIPELINE SYSTEM
BEAUFORT SEA
ALASKA

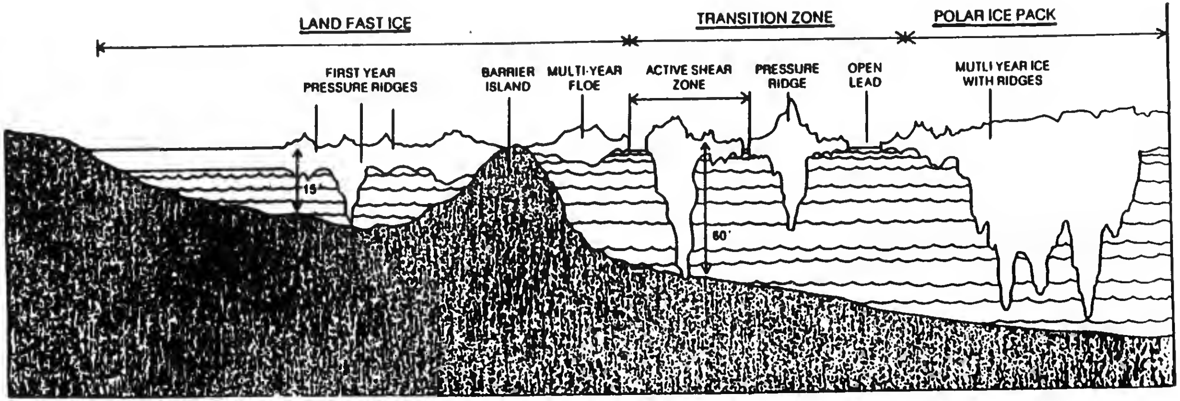
M-2

ENVIRONMENT (E)

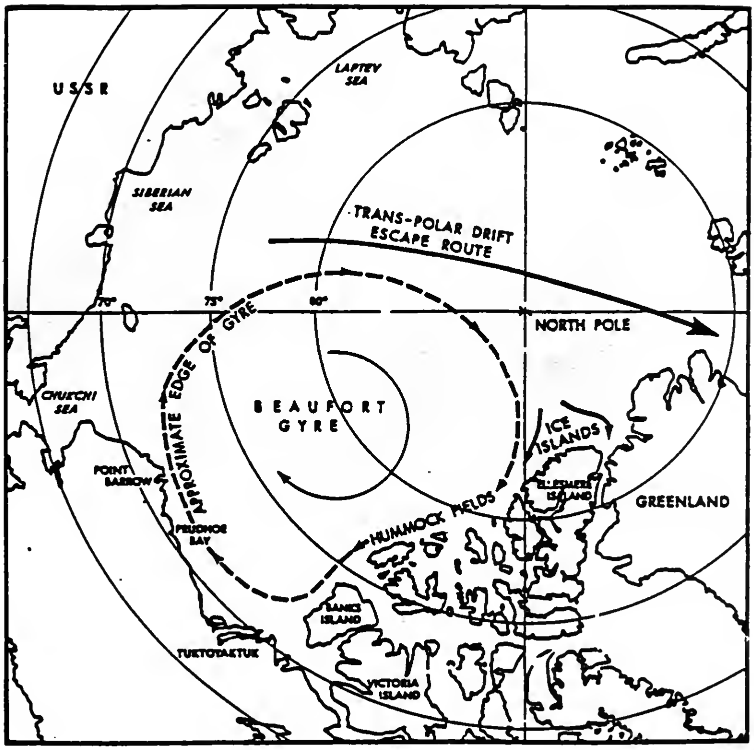
ARCTIC OPERATING CONDITIONS



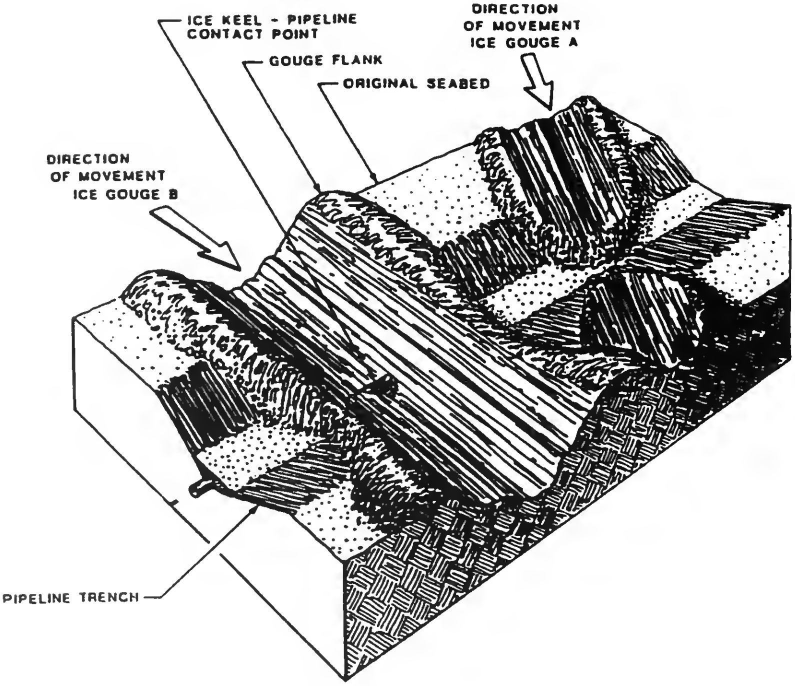
ARCTIC ICE ZONES



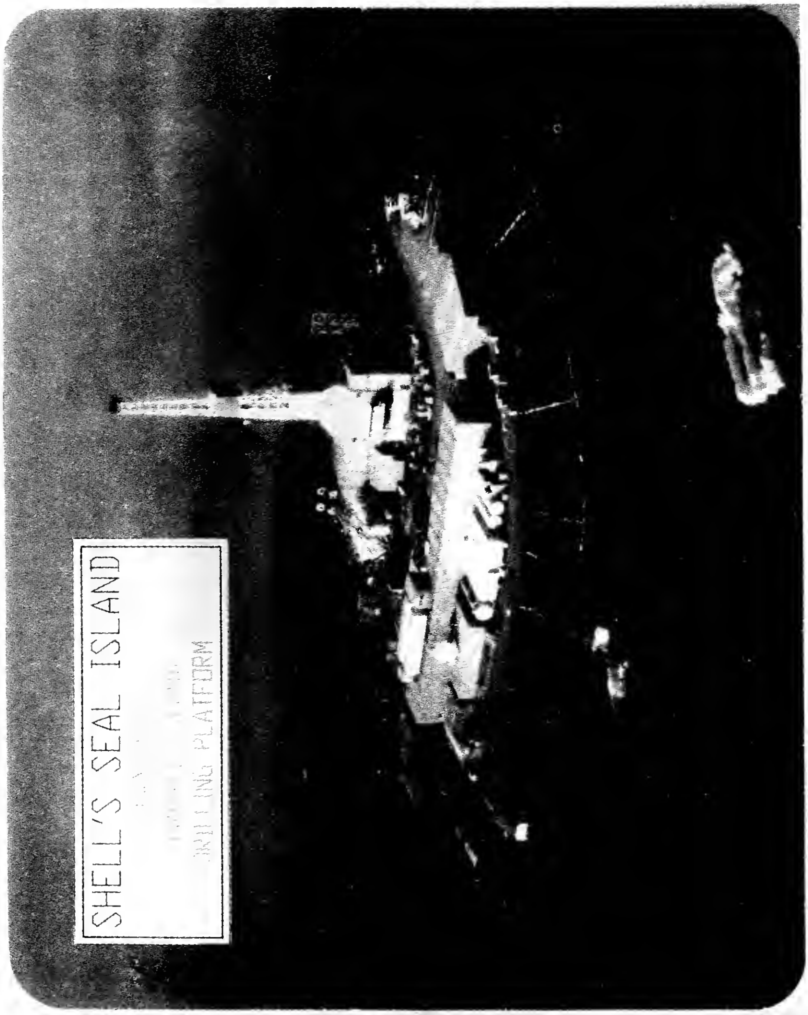
GENERAL MOVEMENT ROUTES
OF
ICE ISLANDS
IN THE
ARCTIC OCEAN



ICE SCOUR - PLAN VIEW



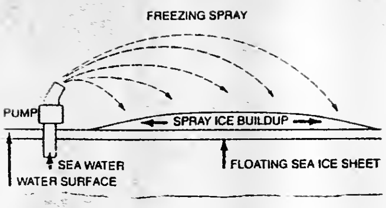
DRILLING (D)



D-1

CONSTRUCTION OF A SPRAY ICE ISLAND -

1

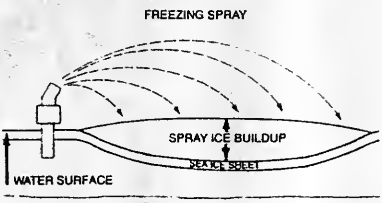


STAGE I -

SPRAY ICE BUILDS UP ON FLOATING ICE SHEET -

A pump sprays sea water into the air where it freezes into ice crystals. The crystals fall onto a floating sheet of sea ice and build up a thickness of spray ice.

2

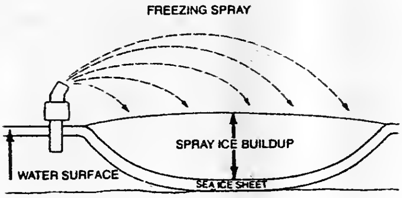


STAGE II -

SPRAY ICE AND SEA ICE SHEET START TO SINK -

The increasing weight of the spray ice build-up causes both the buildup and the sea ice sheet beneath to sink.

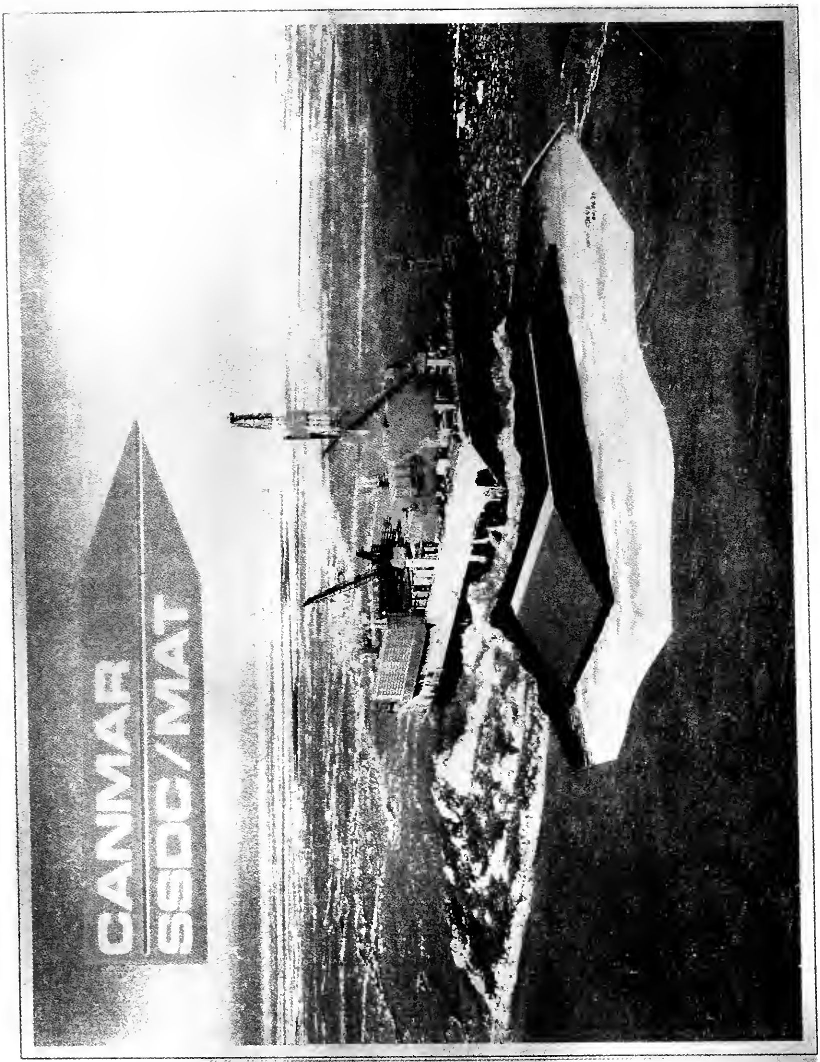
3



STAGE III -

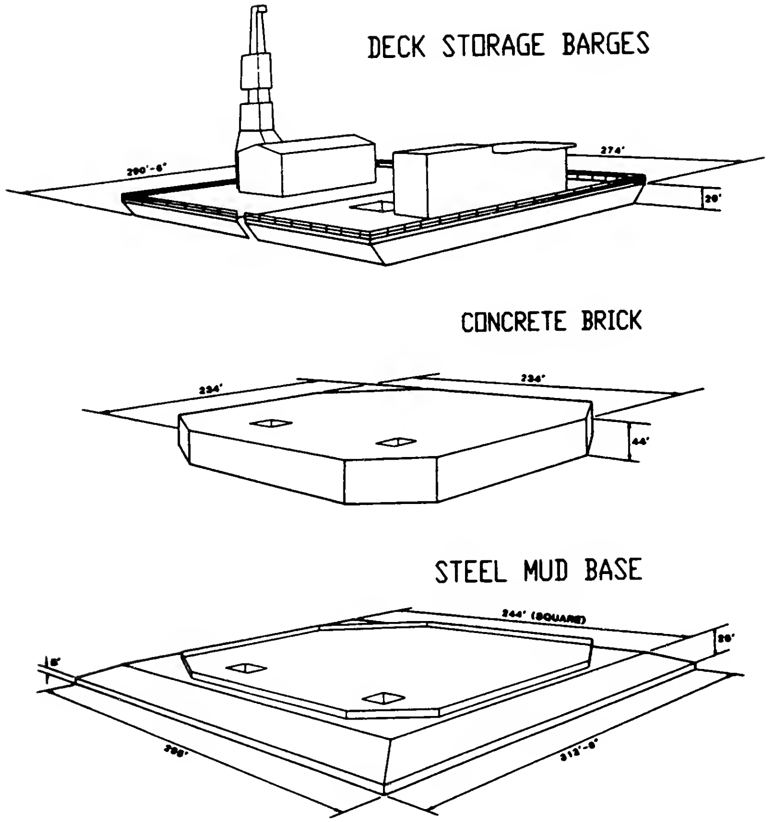
SPRAY ICE AND SEA ICE SHEET ARE GROUNDED ON SEA FLOOR -

Eventually, the spray ice buildup depresses the sea ice sheet until it rests on the sea floor. A grounded island has been formed.


CANMAR
SSDC/MAT

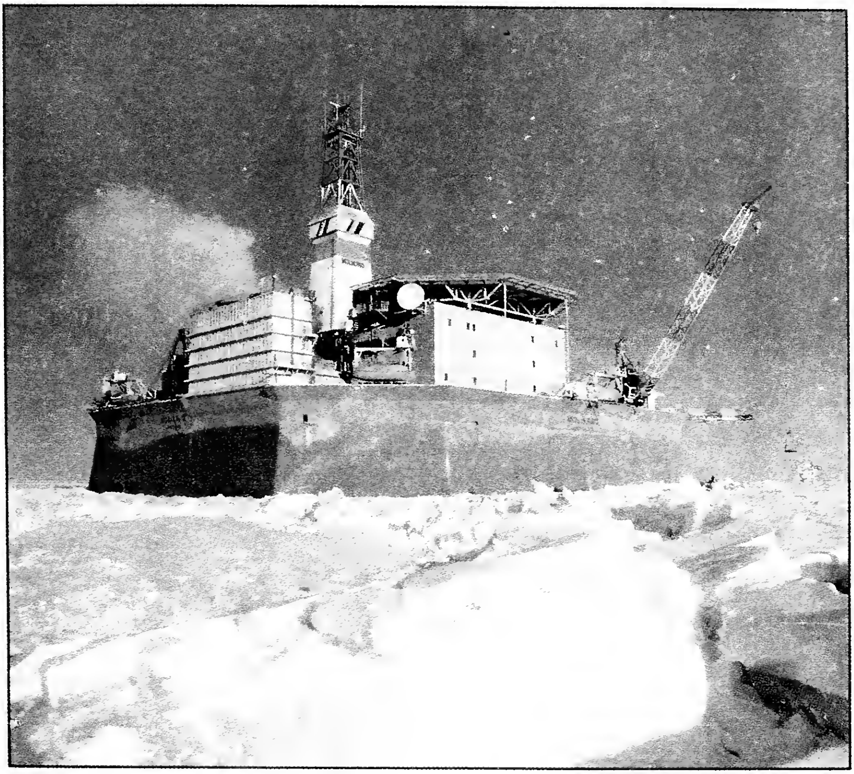

GLOMAR BEAUFORT SEA I
GLOBAL MARINE DRILLING COMPANY

– GLOMAR C.I.D.S. –


DECK STORAGE BARGES
274'
CONCRETE BRICK
234'
234'
44'
STEEL MUD BASE
244' (SQUARE)

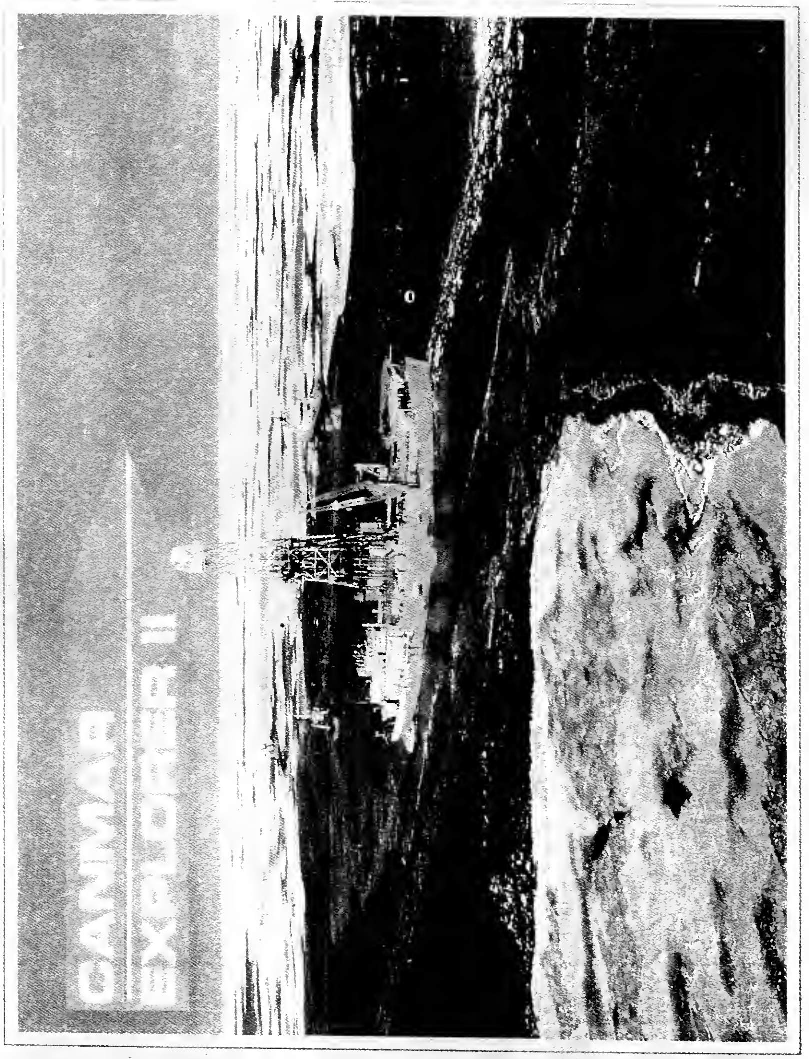
Molikpaq

Mobile Arctic Caisson



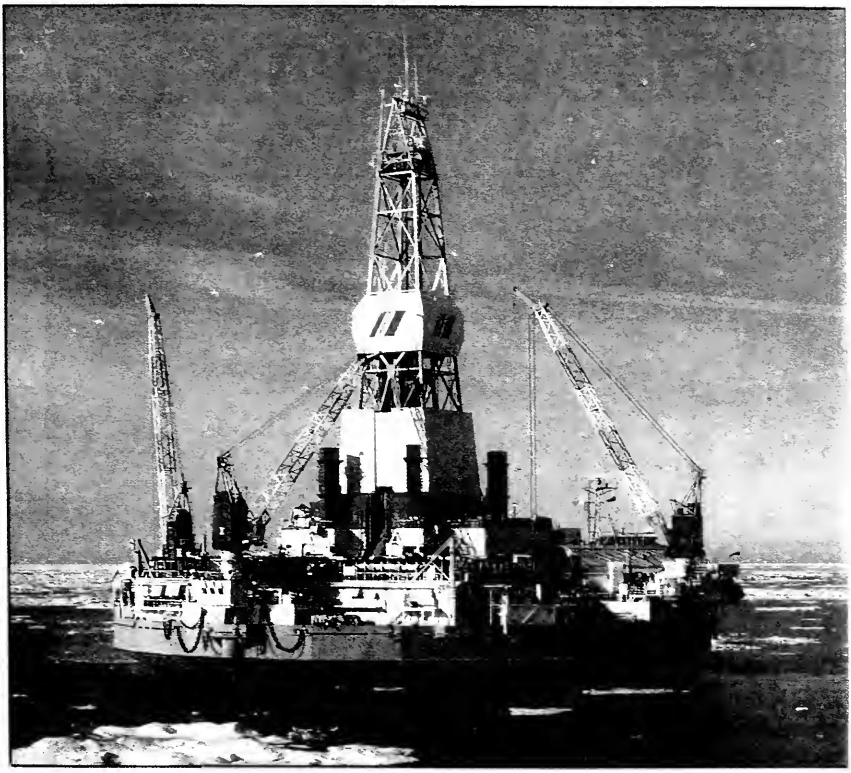
D-6

74-587 O - 93 - 5


CANMAR
EXPLORER II

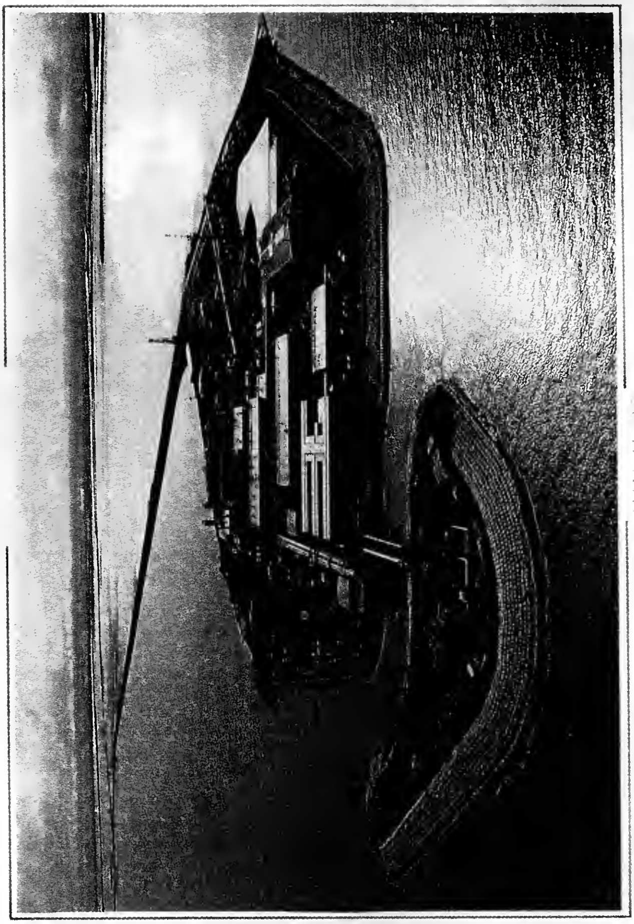
Kulluk

Conical Drilling Unit

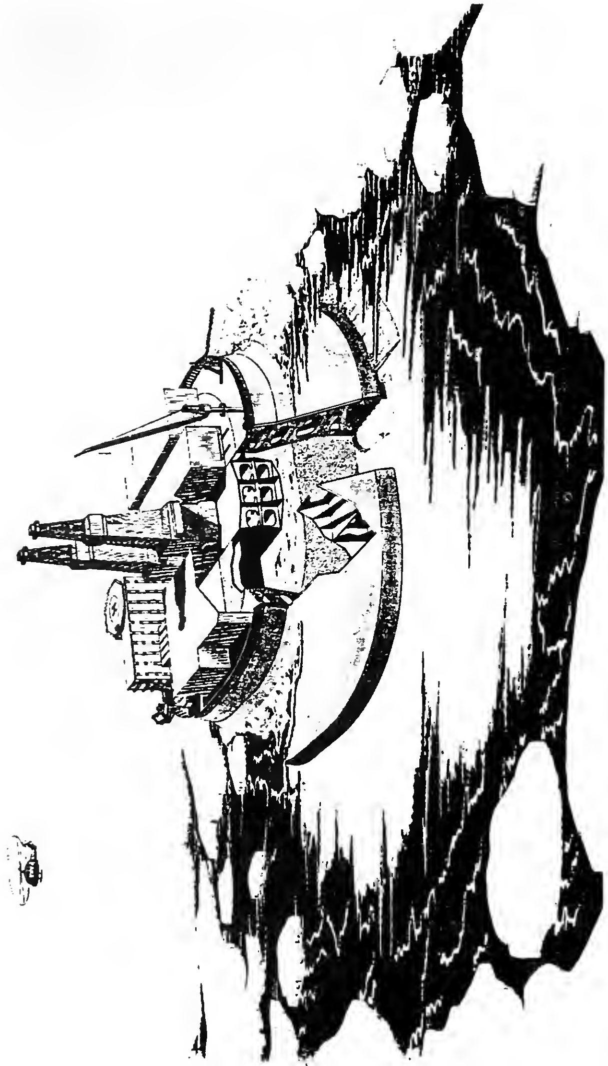


PRODUCTION (P)

ENDICOTT

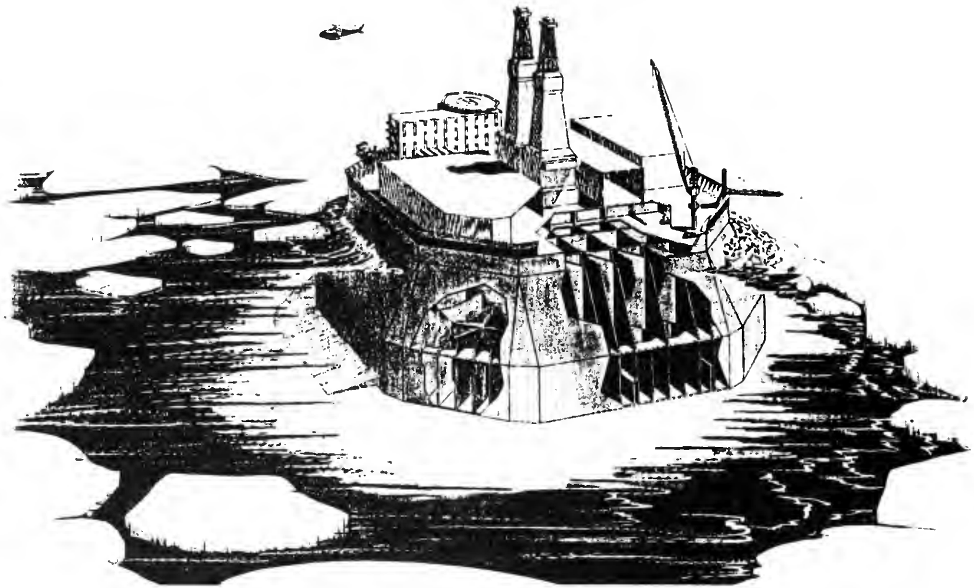


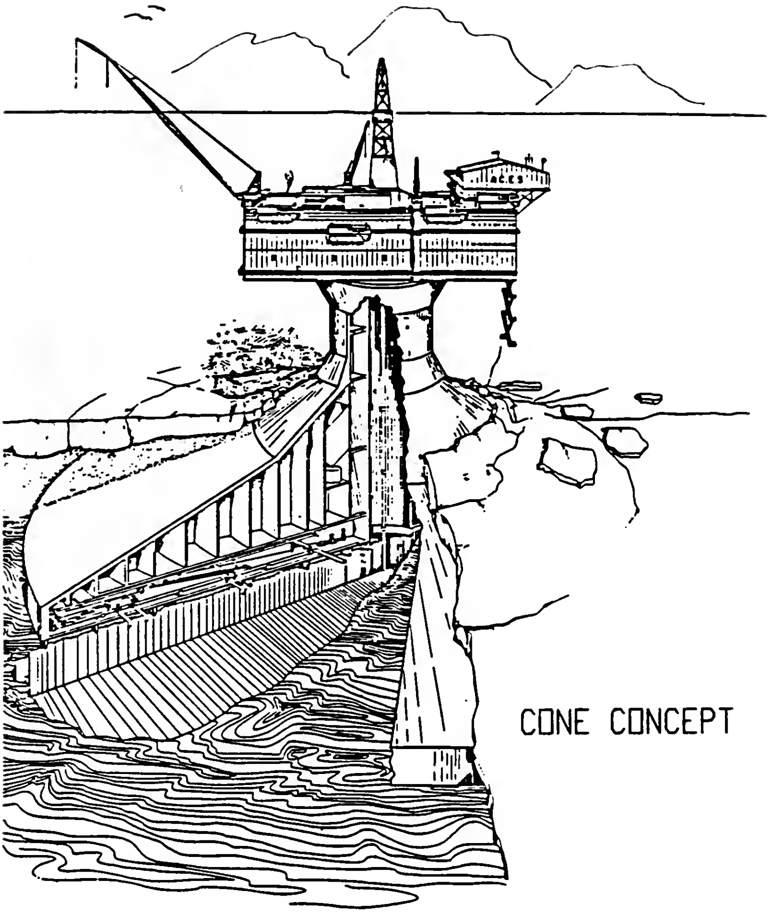
MAN-MADE
GRAVEL ISLAND
PRODUCTION FACILITY



STEEL PRODUCTION PLATFORM

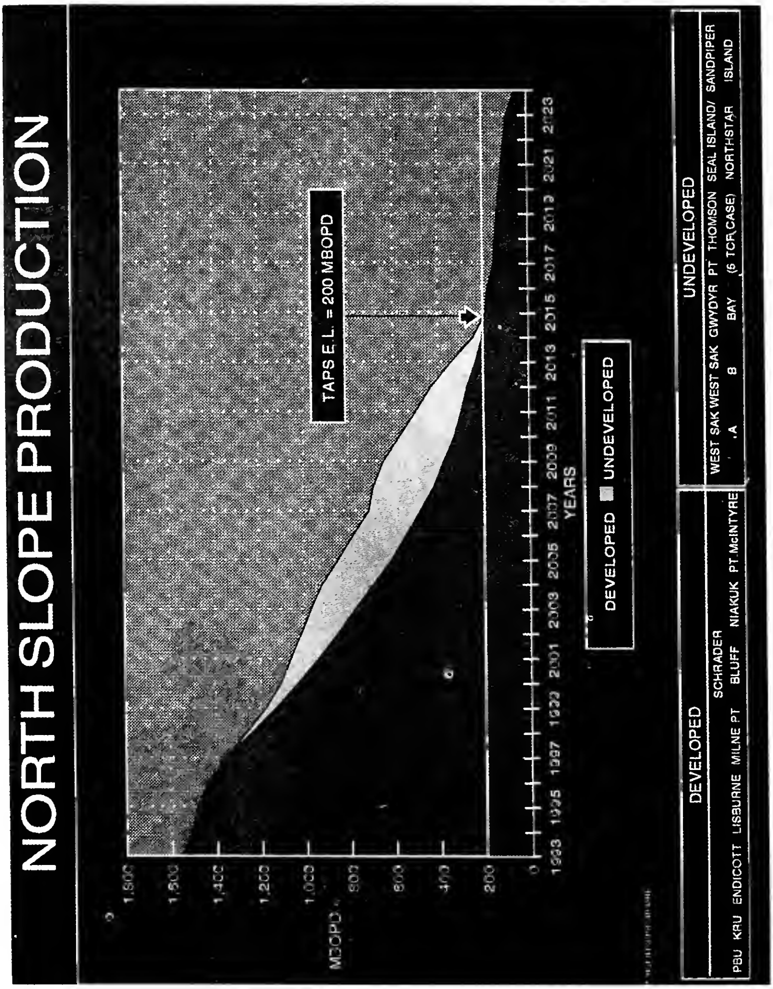
CONCRETE PRODUCTION PLATFORM





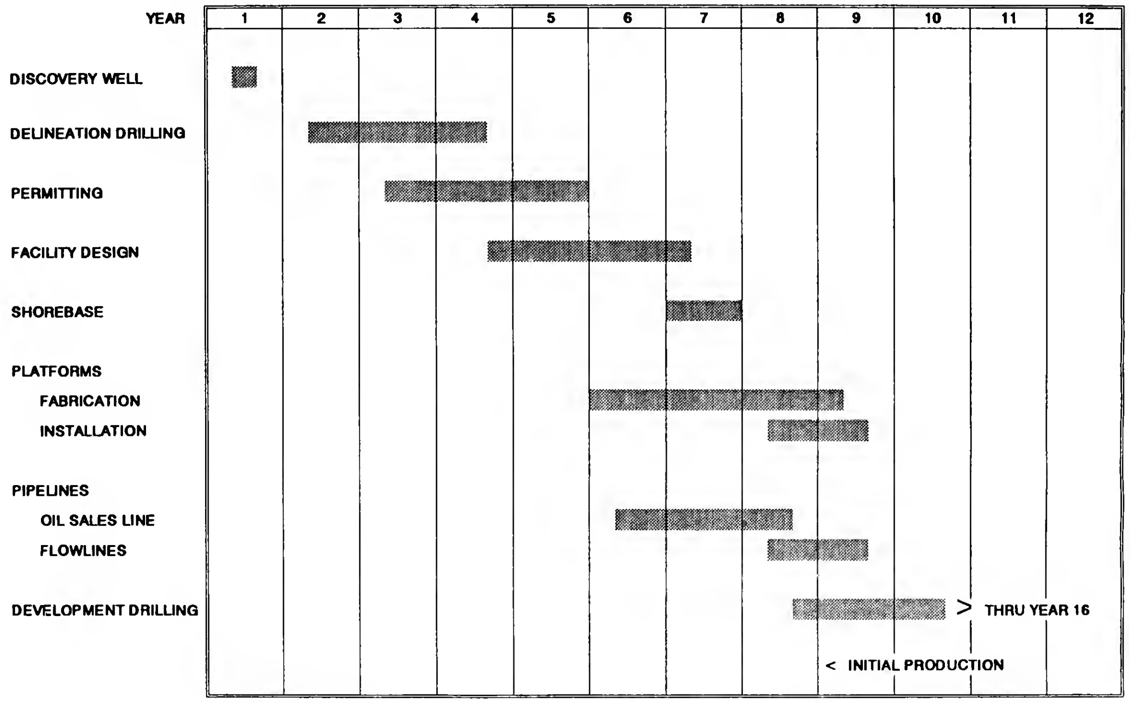
CONE CONCEPT

TIMING (T)


NORTH SLOPE PRODUCTION
MBOPD
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
TAPS E.L. = 200 MBOPD
1993 1995 1997 1999 2001 2003 2005 2007 2009 2011 2013 2015 2017 2019 2021 2023
YEARS
DEVELOPED
UNDEVELOPED
DEVELOPED
PBU KRU ENDICOTT LISBURNE MILNE PT SCHRADER BLUFF NIAKUK PT.McINTYRE
UNDEVELOPED
WEST SAK A WEST SAK B GWYDYR BAY PT THOMSON (6 TCF CASE) SEAL ISLAND/ NORTHSTAR SANDPIPER ISLAND

T-1

TYPICAL BEAUFORT SEA PROJECT DEVELOPMENT SCHEDULE



PHILLIPS PETROLEUM COMPANY
HOUSTON, TEXAS 77251-1967
BOX 1967

NORTH AMERICA
EXPLORATION AND PRODUCTION

BELLAIRE, TEXAS
6330 WEST LOOP SOUTH
PHILLIPS BUILDING

October 11, 1993

VIA TELEFAX: 202/225-1134

Solomon P. Ortiz
Chairman
Subcommittee on Oceanography,
Gulf of Mexico, and the
Outer Continental Shelf
U.S. House of Representatives
Committee on Merchant Marine & Fisheries
Room 1334, Longworth House Office Building
Washington, DC 20515-6230

Dear Chairman Ortiz:

Attached are responses to the list of questions you provided following the hearing on the Outer Continental Shelf Enhanced Exploration and Deep Water Incentives Act (H.R. 1282) on Tuesday, September 14, 1993.

Thank you for allowing me the opportunity to participate at the hearing and if you have any questions, please feel to contact me at 713/669-7465.

Sincerely,

Randy L. Nesvold
Alaska Area Operations Manager
North America Exploration & Production

RLN:lss

Attachment

HEARING ON OFFSHORE OIL & GAS INCENTIVES
RESPONSES TO QUESTIONS ARE DUE: October 29, 1993

QUESTIONS FOR RANDY NESVOLD:

1. What effect will the proposed incentives have on industry's willingness to develop deep water or marginal areas? What can be done to stimulate deep water or marginal areas without legislation?

Any incentive that enhances the potential financial rate of return on a prospect will stimulate investment. When making an exploration or development decision, an operator must weigh the potential income a project may generate against the economic risks associated with the project. Higher risk areas such as the arctic, deep water or other marginal projects, require much higher potential financial rewards to make the prospect economically attractive. Any incentives that increase the potential rate of return on an investment will allow operators to take greater risks and as a result, stimulate exploration in frontier areas and development of marginal prospects.

However, tax code or royalty relief benefits are probably not sufficient to encourage a surge in leasing and development of high risk, high cost areas, such as the deep water prospects in the Gulf of Mexico. Unlike the highly successful, broad-based Section 29 Tax Credit Program, deep water incentives would benefit only a few major players who can stand the extraordinary risk associated with deep water exploration. For example, Phillips has no leasehold in greater than 400 meters of water depth and only a very small interest in water depths greater than 200 meters. In general, only a small group of the largest oil companies would benefit from incentives limited to deep water. Broad-based incentives that benefit both large and small companies have the greatest impact on stimulating development of new oil and gas production. The most effective means of stimulating investment from all segments of the domestic oil and gas industry, and ultimately reducing our dependence on foreign oil, is to implement incentives that apply to any marginal prospect and that are grandfathered to include existing leases.

Additionally, a key consideration companies must take into account is the unpredictability of incentive programs, especially tax incentives. Congress has a history of legislating energy incentives only to remove them from the code or allow them to expire a short time later. This is a significant concern on long lead time projects such as in the arctic and the deep waters of the Gulf of Mexico. If an incentives program is enacted, there must be assurances that it could be utilized for the duration of the project unless the need for the incentive was offset by higher energy prices.

In regard to stimulating investment without additional legislation, the MMS Director (upon application by the lessee), has the authority to reduce or eliminate royalties to increase production. This regulation is seldom used because it is poorly understood and requires clarification. While royalty relief might be of benefit to lessees who already have deep water projects, it is unlikely such relief will stimulate an aggressive deep water leasing and drilling program.

2. ***Approximately what percentage of your company's total exploration and development budget goes to foreign projects? Will this legislation help to bring some of this money back to the U.S.? Will the development of these deep water areas be accomplished through the use of U.S. service companies?***

   In 1992, 63% of our exploration and production budget was spent overseas. This is compared to only 44% as recent as 1990.

   Any legislation that makes U.S. prospects more competitive with overseas prospects will stimulate increased investment in U.S. oil and gas exploration and development. However, the proposed legislation will not be sufficient to stimulate a surge in domestic investment. If the Federal Government wants to encourage increased domestic investment, it must revisit many of the policies which have been implemented in recent years, ranging from OCS moratoria to tax policies (such as the Alternative Minimum Tax).

   Any legislation that stimulates investment in domestic oil and gas projects would have a positive effect on domestic oil and gas service companies.

3. ***Does deep water or frontier area drilling and production require any additional environmental safeguards? If there are any, what are your companies doing to address these safeguards? Has there been any research completed to address this issue?***

   Phillips is not currently active in deep water exploration, but in frontier areas such as the arctic as well as all other areas in which we operate, Phillips plans to conduct all activities with a minimum impact to the environment.

   Currently, Phillips and our partners are conducting baseline environmental surveys in the Beaufort Sea for use in preparing Environmental Impact Reports.

The DeepStar Project

by

J. P. Wilbourn, S. A. Wheeler, C. D. Burton
Texaco, Inc. - Central Offshore Engineering

DeepStar entered its second year of operation in March of 1993. The goal of the program is the cooperative industry development of technology to facilitate commercial development of deepwater tracts using subsea technology. DeepStar is a Texaco administered consortium of 15 major operators (Participants) and 30 supplier/vendor organizations (Contributors). Participants in the Phase 2 program include:

- Texaco
- Shell
- Exxon
- Mobil
- Conoco
- BP
- BHP
- Chevron
- Agip
- Elf-Aquitaine
- Kerr-McGee
- Marathon
- Phillips
- DeepTech
- Arco

DeepStar Concept

Joining together in this industry cooperative effort, progress is being made toward the common goal of having an economic deepwater production strategy and the necessary technology and equipment ready for field use by the latter half of this decade. The major technology goals for DeepStar include evolving a development concept capable of:

- Production in water depths to 6,000 feet;
- Accommodation of a broad range of produced fluid properties and rates from various reservoir types;
- Subsea satellite production to host platforms up to 60 miles distant (platform depths 600-800 feet);
- Installation of the subsea facilities in a staged program;
- Minimum maintenance requirements;
- Remote operated vehicle installation and maintenance capability;
- All production operations remotely controlled from the host platform (or potentially, in early field life, from the drilling vessel).

The DeepStar concept employs a phased development strategy. It also focuses on a system approach versus random component designs. The three major stages of the development approach are as follows:

Exploration/Delineation Drilling

Development Phase 1 consists of prospect appraisal during a field's exploration/ delineation to confirm type and extent of a field's reserves and determine initial production traits (i.e., probable fluid characteristics such as flow rates, pressures and composition). Assuming drill-stem tests are encouraging, a decision may be made to complete these exploration/delineation wells with equipment suitable for longer term testing using three to five wells as producers during Phase 2.

Evaluation/Early Production

Development Phase 2, or the Evaluation/Early Production phase, will confirm the basic operability of the production system with relatively low capital commitment. At the same time, the produced oil and gas will both furnish revenue to help defray Phase 2 costs, and also provide still more (longer-term) reservoir information to augment the Phase 1 drill-stem tests. During this phase, the operator would produce the three to five delineation wells to determine if field performance is sufficient to warrant full field development. If, during Phases 1 or 2, a conclusion is reached that the field is not worth developing, then an abandonment decision may be made. Under these circumstances, the objective is to minimize financial loss, assuming production revenue is insufficient to provide a net profit.

Full Field Development

Phase III development depends on the reservoir size and type. For reservoirs requiring only 10 to 15 producing wells, a small development concept is appropriate. For 30 to 40 wells, a large development effort would be pursued. Data and experience gained in earlier phases would be employed in decision-making regarding Phase III development.

One of the critical assumptions for this study was that the field would be offset a significant distance (25 to 60 miles) from a shallow water host platform. This overall concept is reflected in the project logo shown in Figure 1. The system schematic for such a subsea tie-back development is shown in Figure 2. Under the DeepStar concept, initial deepwater subsea production operations will attempt to use existing platforms as host processing facilities. As confidence in the deepwater prospect is established, a staged expansion of the subsea facilities would be initiated as described above. Such an expansion would most likely require the construction of a new dedicated processing center. Once established, this center would be capable of handling production from a number of other deepwater prospects within a 60 mile radius (reference Figure 4). Subsequent developments in the area will be achievable at a reduced cost (estimated at 75% to 80% of original cost per barrel) compared to the first project which established the processing center. The existence of new deepwater infrastructure will facilitate the commercial development of small fields (50 MMBOE or less) which would normally not be considered economically attractive on their own. An opportunity exists here for the industry to again cooperate and establish joint processing centers that could service an entire region (reference Figure 3). A joint industry processing center approach could still prove attractive even if the development concept adopted by several of the venture operators did not involve subsea production wells.

Phase 1 Technology Studies

The DeepStar team documented and evaluated the capability, cost and availability of basic components and subsystems that would potentially be required for a remote subsea development through a series of foundation studies which included:

- Multi-phase subsea pumps and subsea separators
- Multi-phase and single-phase pipeline systems
- Control systems and umbilicals
- Chemical injection systems
- Templates and manifolds
- ROV systems
- Diverless/guidelineless modularization
- MODU production support operations and safety

The results of specific investigation in these areas provided recommendations as to the best types or family of components for use in deepwater subsea systems to meet an actual field development within the next two to five years.

DeepStar Phase 2 Work Program

The work program for 1993-94 of the DeepStar Project is broken into 10 major technology focus areas: Regulatory, Multiphase Flow & Equipment, Controls Issues, Production Risers, MODU & Mooring, Flowlines & Umbilicals, Reservoir Performance & Engineering, Manifolds/Trees & Connections, Produced Fluids, and Drilling & Completion Issues. Work in each focus area is overseen by a chairman and a technical committee consisting of representatives from each of the participating companies. The following engineering organizations have been contracted by the project to perform a number of specialized technology scoping studies.

- Intec Engineering (Program Technical Advisor)
- Aker Omega
- H. O. Mohr Engineering

Oceaneering Production Systems
- Sonsub
- Project Associates

One of the unique aspects of DeepStar is that Participants are sharing prior technical research in an effort to "leap-frog" technology development in these key focus areas and to do so at minimum cost. The following is a synopsis of progress to date in each of the technology development areas.

Regulatory Issues

A number of regulatory related barriers exist for development of the deepwater Gulf of Mexico. Representatives of the DeepStar participant companies have been meeting on a monthly basis with the Minerals Management Service (MMS) to discuss technology issues and current regulations in an effort to identify areas where existing regulations are not in step with technology capabilities. Areas of discussion have included production monitoring & testing, underwater safety valves, shut-down requests, suspension of production, and subsea installation/maintenance and repair. Extended well test operations have also been the subject of discussions and will be the topic of a special report to be issued later this year.

Multiphase Flow & Equipment

Texaco has released the results of an in-house Transportation Options Study to DeepStar Participants which focused on the transport of multiphase fluids over long distances (up to 60 miles) in extreme water depths (2,000 - 6,000 ft). This work will form the basis for further joint study work by the DeepStar group on issues related to multiphase transport and the options open to the industry to add energy to multiphase fluid systems. Many of the major technical hurdles associated with deepwater production revolve around the challenges that arise from production in the cold environment associated with deepwater. Examples are: produced fluids problems such as hydrates/paraffins, and the phase behavior of the fluids being transported. Initial study work focused on the Gulf of Mexico and showed that 1) reservoir depletion via natural flow is possible for a period of time. This period of time will depend on reservoir and fluid properties. The period of time is likely to be in excess of that required for the initial reservoir evaluation/early production phase of a DeepStar type development, 2) an economical method of controlling hydrates will be essential for any extended reach development producing significant quantities of water, 3) hydrates may be controlled either by prevention of hydrate crystal formation or by controlling agglomeration of the hydrate crystals once formed. The method of hydrate control will be either via chemical, thermal or mechanical means. The method of hydrate control used will have a major impact on the type of multiphase flow system, which can be used and vice versa. This arena of work promises to be one of the areas of key focus in ongoing DeepStar activities.

Control System Issues

The purpose and intent of this work group is to evolve the architecture and direction of control system developments in the next generation of deepwater control systems. Areas proposed for study include autonomous control systems, umbilical improvements, basic system architecture, interface of control systems with subsea pumps & separators. This group has met on several occasions with representatives of the various vendors and contractors that are acting as contributors to the DeepStar work. A scope of work has been issued to interested parties identifying areas of concern, technology requiring further development, and basic questions the operator community has concerning system capabilities for deepwater deployment.

This work group is being supported by Contributor representatives from FSSL, GEC, Hydril, Ocean Design, Marston Bentley, Pirelli, Tronic, Multiflex and Koomey.

Deepwater Production Risers

This group is attempting to focus the industry's deepwater riser development efforts on a small number of promising production riser concepts. These include flexible, rigid/buoyant, composite, and hybrid approaches. The intent for this year's activity is to compare and perform a screening analysis of possible options. In the 1994 work program the surviving concepts will be developed and modelled in greater detail, with a possible progression to wave tank testing or hardware development. To assist in their analysis work, the committee has a clearly defined design basis complete with environmental conditions for a variety of Gulf of Mexico potential deployment sites.

This work group is being supported by Contributor representatives from Coflexip, Wellstream, Cooper and Hydril.

MODU & Mooring

One of the key aspects of DeepStar will be the ability of existing drilling vessels to simultaneously drill, moor, and accommodate limited production functions in deepwater. Study efforts by this group are targeted with addressing issues such as these in addition to exploring innovative mooring system designs that could dramatically lower the cost of deepwater mooring systems.

The first part of the effort will concentrate on evaluating the ability of existing drilling semisubmersibles to moor and drill in water depths between 3000 ft and 6000 ft. Given that this is economically feasible, the next step is to add minimal process facilities for extended well testing/early production and finally to produce the field long term. Mooring design criteria for both extended well testing and long term production are more onerous than for drilling alone and may require modifying or replacing the existing mooring system. The additional deck load due to the modified mooring system, deepwater drilling equipment and consumables, production risers, and the process system can easily exceed the capacity of existing drilling vessels. The vessels, therefore, may require structural upgrades as well to increase the buoyancy and deck load capacity.

The second part of the study will concentrate on cost reduction measures. These will include alternate mooring designs such as taut leg systems or DP-assisted mooring, process system weight reduction, and the effect of downtime due to disconnecting and retrieving the drilling riser.

This work effort is being supported by several Contributors. Reading & Bates, Sonat, and Sedco-Forex are evaluating vessel and drilling capabilities and determining upgrade requirements to accommodate increased water depth, deck load and space requirements. Baker-Hughes is evaluating process system alternatives and Imodco is evaluating FPSO and mooring system options.

Flowlines & Umbilicals

This work group is charged with identification and development of new, innovative, low cost methods of flowline/pipeline installation and repair as well as development of alternative umbilical concepts for ultra deepwater. The group currently is at work on a number of topical concerns. These include two alternatives for pipeline repair in water depths to 6000 ft, new (low cost) J-lay techniques and tooling, pigging studies for deepwater systems, and fabrication of umbilicals from alternative materials.

This work effort is being supported by Contributors including OPI, Heerema, Sonsub, Multiflex, Pirelli Cable, Stena, Marston Bentley, and Oceaneering.

Reservoir Performance & Engineering

This group's activities are focused on identification and documentation of characteristics of deepwater reservoirs in the Gulf of Mexico. Characteristics of the deepwater reservoirs, including their size, productivity, and fluid make-up, will have a direct bearing on the economic viability of deepwater development. The participants in DeepStar are pooling data collected to date on deepwater reservoirs in an effort to understand better what design parameters should be used in planning deepwater developments.

Manifolds, Trees & Connections

The focus of this work group includes all aspects of subsea hardware. This includes preferred facility arrangements (template vs cluster, satellite, etc.), interface connections, installation considerations, standardization of equipment/interfaces, manifold configuration, tree layout, intervention, maintenance, and repair. The group is also attempting to evolve and adopt standard designs for workover/completion equipment, trees, and manifolds.

Efforts within this work group are being assisted by the following Contributors: Heerema, Cooper, Hydril, National Oilwell, FMC, ABB Vetco, Wellstream, and Coflexip.

Produced Fluid Problems

Second only to reservoir questions, produced fluids problems are seen as the major barrier to economically viable production from the deepwater Gulf. Of special concern to the Participants is paraffin production, followed closely by hydrate formation and asphaltene production. The Participants are evaluating data on these fluids problems in an attempt to identify a direction to focus expenditure of joint funds. Alternative methods for handling produced fluid problems are being evaluated including thermal, chemical, and mechanical treatments. As is the case with the reservoir group, the produced fluids team is collecting data on the different produced fluids problems that have been encountered in the deepwater Gulf. This data will be used to focus the group's activities on those aspects of the problem that will most favorably impact the potential for future development.

One of these areas is the need to develop standardized well test procedures and tools for testing of exploration wells. The committee has issued a letter of inquiry to a number of manufacturers in the downhole tool industry with the intent of developing a standard tool for use in taking downhole fluid samples.

Drilling & Completion Issues

The single largest expenditure for deepwater developments will be well drilling and completion costs. This activity alone accounts for between 40 and 70% of the cost of deepwater developments. When viewed in the light of total development costs, this could exceed $700 million. Cost control and reduction is critical to the effort to make the deepwater Gulf commercially viable. The Participants are focused on identifying those actions that can be taken to reduce drilling, completion, and intervention costs.

Participants are being assisted in this area by the following Contributors: Reading & Bates, Sonat, Sedco-Forex, Profco, CTC International, Baker Hughes, Halliburton, Hunting Oilfield, Hydril, OSCA, and Bardex.

Conclusions

DeepStar is redefining the way major operators, suppliers, and government agencies can work together to promote development in technically challenging environments such as the deepwater Gulf. The program has been operational for almost two years. As can be seen from this report, many technology issues critical to the progress of deepwater development are being addressed and innovative development concepts and approaches are being evolved.

DeepStar - Industry Teaming Up To Develop A Deepwater Concept

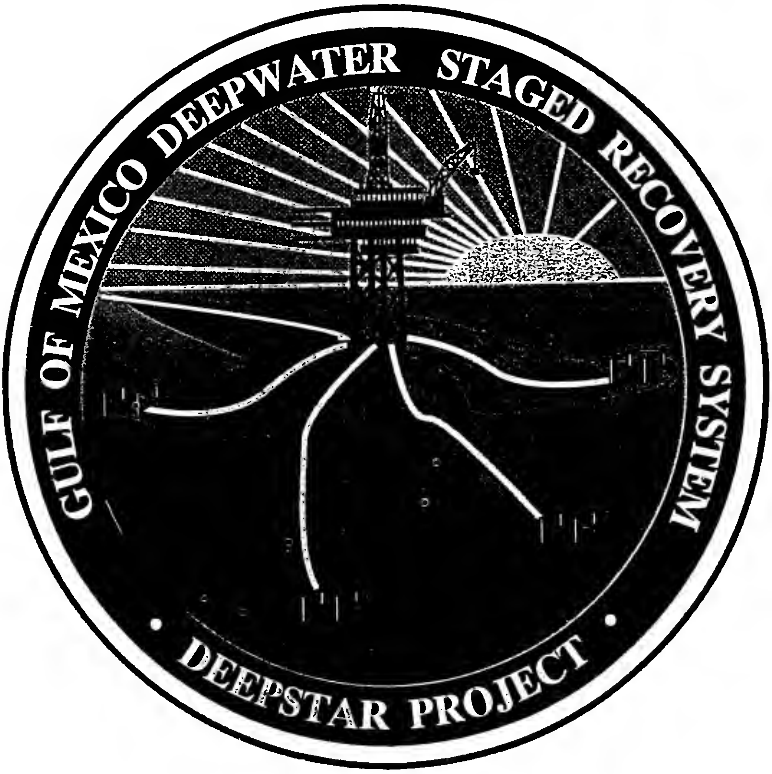


Figure 1

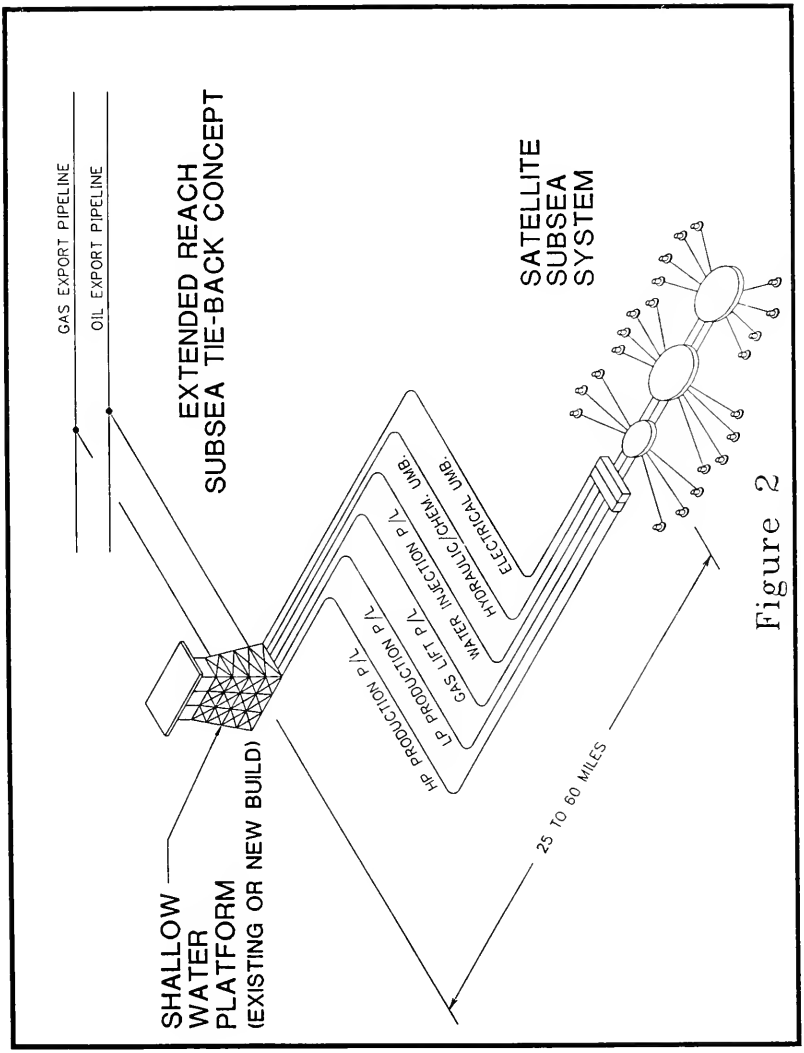

GAS EXPORT PIPELINE
OIL EXPORT PIPELINE
EXTENDED REACH
SUBSEA TIE-BACK CONCEPT
SATELLITE
SUBSEA
SYSTEM
SHALLOW
WATER
PLATFORM
(EXISTING OR NEW BUILD)
HP PRODUCTION P/L
LP PRODUCTION P/L
GAS LIFT P/L
WATER INJECTION P/L
HYDRAULIC/CHEM. UMB.
ELECTRICAL UMB.
25 TO 60 MILES

Figure 2

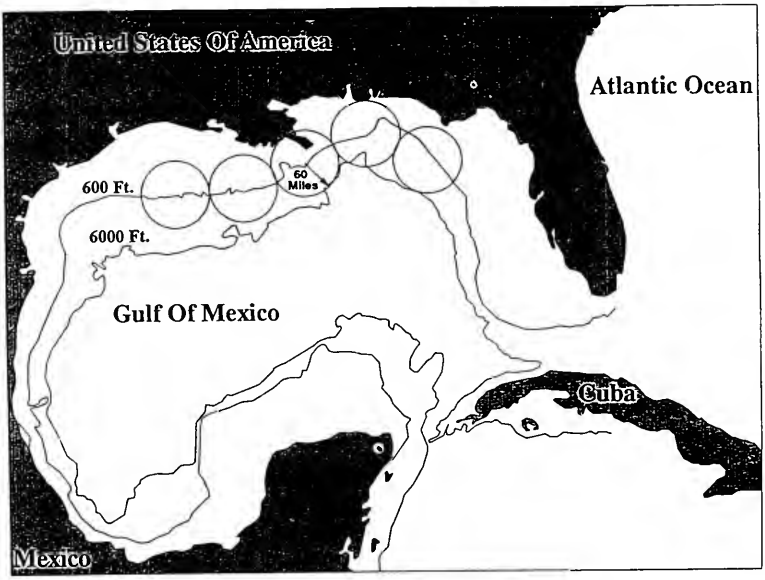


Figure 3 - Gulf Of Mexico (600 - 6,000 Ft Contour)

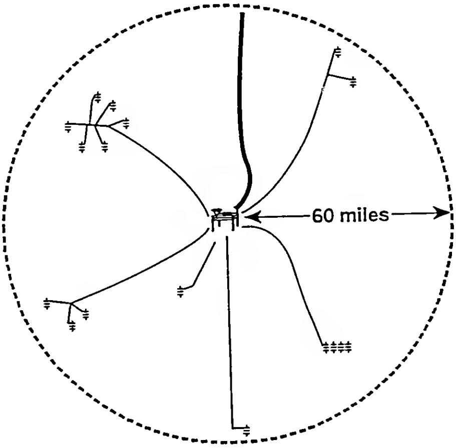


Figure 4 - Central Processing Platform

James C Pruitt
Vice President
Federal Government Affairs

Corporate Communications
a Division of Texaco Inc

1050 17th Street NW
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October 12, 1993

The Honorable Solomon P. Ortiz
Chairman
Subcommittee on Oceanography, Gulf of Mexico
and the Outer Continental Shelf
575 Ford House Office Building
Washington, D.C. 20515-6230

Dear Mr. Chairman:

I refer to your September 15, 1993 letter with additional questions concerning J. Phil Wilbourn's testimony at the September 14, 1993 Subcommittee on Oceanography, Gulf of Mexico & Outer Continental Shelf hearing on the Outer Continental Shelf Enhanced Exploration and Deep water Incentives Act (H.R. 1282).

Enclosed is Texaco's reply to the questions raised by yourself as well as those posed by Congressman Jack Fields. If there are further questions or if you need clarification on the attached, please advise.

Yours very truly,

James C. Pruitt

JCP:hg
Attachment

I. **What effect will the proposed incentives have on industry's willingness to develop deep water or marginal areas? What can be done to stimulate deep water or marginal areas without legislation?**

a) **The royalty relief bill is a positive step, but will have marginal impact on allowing a project to go forward. The after tax net present value increase of the royalty relief is about 10%. It is unlikely that this increase alone would enhance a project's value enough to cause many marginal discoveries to be developed. The tax credit bill by Senator Breaux (S.403) would more directly influence the decision to proceed with a marginal discovery. The value with the appropriate tax credit does increase the economics enough whereby a marginal project may become economically attractive and developed.**

b) One possibility is to allow gas flaring for an extended period. Long term production tests allow for a much more accurate reservoir assessment, thus decreasing the risk of moving forward with development. Additionally, in some extreme cases, it may not be economical to lay a gas pipeline; however, tankering the produced liquids would likely be profitable. Accordingly, tankering as an alternative means of development should be available to industry.

II. Approximately what percentage of your company's total exploration and development budget goes to foreign projects? Will this legislation help to bring some of this money back to the U.S.? Will the development of these deep water areas be accomplished through the use of U.S. service companies?

a) In 1993, Texaco's budget outlined the following split between foreign and domestic exploration and development expenditures:

foreign = 55%

domestic = 45%

b) The proposed legislation will bring some of the money back to the U.S. by virtue of some U.S. projects, especially the marginal fields, being more economically attractive when compared to the foreign portfolio of opportunities.

c) U.S. service companies will certainly have the opportunity to carry out this additional work provided they are competitive. The U.S. has begun to lose its leadership role in the development of offshore technology due to foreign governments, quasi-government petroleum societies and national oil companies' sponsorship of this activity. However, as we have seen in the past, if there is an application the entrepreneurship of the U.S. service companies will provide the resources and brain power to develop the tools and equipment needed.

III. Does deep water or frontier area drilling and production require any additional environmental safeguards? If there are any, what are your companies doing to address these safeguards? Has there been any research completed to address this issue?

a) The existing regulatory controls for the offshore industry are more than adequate to protect the environment.

b) Texaco has its own worldwide E&P Environmental Practices for exploration and production operations that are designed to protect the environment in all operating conditions.

c) Both DOE and API have conducted field research around offshore drilling and production facilities. These studies have shown that there is minimal impact from properly conducted operations in shallow waters where effluents may not be as well dispersed as in deep water. Dispersion studies have verified these conclusions.

d) In 1990 Texaco established an Environmental, Health and Safety Division in order to strengthen its record of performance in the broad array of environmental, health, and safety matters. Paramount in the EHS Division is the ongoing initiative to strengthen our ability to respond to oil spills. As part of this program, Texaco conducts emergency drills in each of its U.S. East Coast, West Coast and Gulf Coast regions. These exercises provide much needed experience for our employees and contractors on how to control and mitigate the effects of an oil spill.

e) Texaco has also joined with other oil companies to improve response to oil spills by its participation in the Marine Spill Response Corporation (MSRC). The MSRC assembles oil spill response experts and stockpiles against the possibility of future spills. In addition, a formal agreement among API members called "Petro-Assist" is in place whereby each member volunteers to provide resources to other members in time of crisis.

1. How much of your current exploration budget is spent in the U.S.?

   In 1993, Texaco budget projects the following split between international and domestic exploration and development expenditures:

	1993	10 Yr. Avg. 1992-1983	15 Yr. Avg. 1992-1978
Int's	55%	40%	39%
Domestic	45%	60%	61%

2. How does that compare with ten or fifteen years ago?

   See Answer to #1 Above.

3. If other incentives such as tax credits were offered would that change your decision to go abroad with your exploration budgets?

   Senator Breaux's tax credit proposal significantly increases the value of a discovery. Small finds that would be otherwise uneconomic may be developed with a reasonable rate of return. The Gulf of Mexico (GOM) is one of the most prolific hydrocarbon provinces in the world. Finding accumulations in the deep water is not nearly as difficult as finding economic accumulations. A tax credit would make more discoveries economic, and should lead to increased exploration and development activity in the GOM.

4. Are there any areas other than the Gulf where some type of royalty relief should be offered?

   The Bureau of Land Management has a program of reduced royalty rates for marginal oil wells located on onshore federal lands. This program should be continued and expanded to include marginal gas wells. A program for marginal oil and gas properties and enhanced oil recovery projects located on Minerals Management Service leases should be considered.

5. If some type of incentive is not available, how cost effective is it to explore Arctic areas?

   The Arctic areas present their own set of technological challenges quite differently from the deep water GOM. The Arctic area is not economical without significant accumulations near the existing infrastructure and transportation network.

6. Obviously the cost of technology to develop deep water areas is high. What other technologies such as air quality controls add significant costs to a development project and should be considered for royalty relief?

   Other technologies that have been identified as adding costs to a development project in deep water:

   a) Composite materials to reduce weight and increase strength in:

      1) Risers, production and drilling

      2) Mooring Systems

      3) Flowlines, Pipelines, umbillicals

   b) Power generation with fuel oils

   c) Submersible electric motors, electrical (set) connections

   d) Multi-phase meters and pumps for submersion service

   e) New chemicals for hydrate and paraffin inhibition purposes

   f) Produced water treatment processes and hardware to reduce weight and space

   g) More effective oil and gas treatment processes and hardware to reduce size and weight

   h) More effective instrumentation and control technology and monitoring hardware

7. What other incentives should be considered to make deep water development cost effective?

   One possibility is to allow gas flaring for an extended period. Long term production tests allow for a much more accurate reservoir description, thus decreasing the risk of moving forward with development. Additionally, in some extreme cases it may not be profitable or feasible to lay a gas pipeline; however, tankering the produced liquids would likely be profitable.

8. Would it influence your lease purchasing decision to know at the lease sale whether a lease were eligible for royalty relief?

   Meaningfully royalty relief would cause lessees to be more aggressive in trying to identify viable prospects. However, the attractiveness of a lease would depend solely on the prospect's potential.

9. In your opinion, does the Secretary have the ability to reduce or suspend royalties and is that authority used? How could that authority be expanded to make it more available?

We believe this question is best directed to the Solicitor of the Department of Interior. However, if it is deemed that he has this authority, as we believe he does, we believe it should be delegated to the Regional Director.

10. Would it be more effective if the Secretary could grant royalty suspension or relief <u>before</u> production began?

Certainly, prior granting of royalty relief is required to facilitate planning and decision making. One cannot undertake any reasonable economic evaluation without knowing what the royalty burdens on a particular prospect will be.

11. If moratoria continue off the Pacific and Atlantic coasts, what areas are there left for exploration?

Deep water GOM or foreign opportunities which offer the appropriate rate of return for the assumed risk.

12. Given our need to offset losses to the U.S. Treasury if OMB or CBO project that the legislation will negatively impact the treasury, what suggestions do you have to bring the costs of this legislation down? Is there anything which can be done to help increase deep water production without directly affecting the budget?

Texaco is supportive of an "Environmental Equalization Fee" on imported gasoline and blendstock. Revenues from one such proposal presented to the Ways and Means Committee have been calculated at $1.9 billion over five years, sufficient to provide for a targeted program of domestic drilling incentives supported by both majors and independents.

A Brief Review of Technology and Research

Prepared for the

Hearing on Proposed Legislation to Provide Incentives to Explore, Develop and Produce Domestic Natural Gas and Oil Resources in Frontier and Deep Water Areas of the Outer Continental Shelf

by

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Petroleum Engineering Department

Texas A&M University

College Station, Texas

September 6, 1993

1. **Deep Water Outer Continental Shelf**

2. **Arctic Offshore**

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† Brief Résumé Attached

2

Below are two separate discussions, the first one dealing with the outer continental shelf of the United States, and the second with the Arctic offshore, north of the Alaskan mainland.

Each discussion is split into two parts: Part (a) discusses the kind of exploration drilling that is performed to locate hydrocarbons, and part (b) discusses the actual production of such hydrocarbons.

1. Deep Water Outer Continental Shelf

(a) Exploration Drilling

In water depths to about 300 ft, exploration wells can be drilled from jackup rigs that stand on the ocean floor. In deeper waters, essentially all exploration wells are drilled from floating drilling vessels. There are two distinct types, semisubmersibles and drillships.

The **semisubmersible** is a very stable floating drilling vessel designed to operate in rough weather conditions. It is usually anchored with 6-12 mooring lines to maintain its position over the well that is being drilled. These units currently can drill in water depths up to about 4,000 ft.

The **drillship** is a ship-like vessel specifically designed for floating drilling. Drillships can currently be used in water depths up to about 7,500 ft. In water depths up to 4,600 ft, the drillship can also be moored, but beyond about 4,000 ft the vessel is usually dynamically positioned; i.e., it is kept in place above the wellhead by numerous thrustors (propellers) strategically located around the hull of the vessel.

Research currently is being conducted on finding better and safer ways to drill deepwater wells. Computer models of well drilling and well control techniques are being developed to increase our understanding of the variables affecting well control problems and to aid in the training of drilling personnel by simulating troublesome situations. For example, when abnormally high downhole pressures are encountered in deepwater wells, the control of the well becomes more complicated, so extensive education and training under non-threatening situations is essential for maintaining a safe operation. Some computer models make use of artificial intelligence and expert systems.

Research is also being conducted on the formation of hydrates (ice containing gas molecules in its structure) to understand how hydrates are formed, how they can affect the drilling operation by plugging lines and valves, and how problems resulting from hydrate formation can be handled.

(b) Hydrocarbon Production

Near shore hydrocarbons can be produced through wells that are directionally (non-vertically) drilled from onshore locations. The bottoms of such wells can typically reach about two miles offshore. In a few cases offshore wells have reached as much as three miles horizontally away from the surface location. One recent well in the North Sea had a total horizontal reach of about four miles.

Production in Water Depths to 1,000 Ft

In waters to depths of 1,000 ft, hydrocarbons are generally produced through wells drilled from steel platforms that stand on the ocean floor and are attached to the bottom by steel pilings that penetrate several hundred feet into the ocean floor. The largest bottom-supported platform in the world stands in 1,353 ft of water. Production wells are usually drilled from the platform after platform installation. Extended reach technology is used and wells typically are drilled to bottom-hole locations one or two miles horizontally removed from the platform. On such platforms the oil is separated from the co-produced gas and water, and is transported to shore via pipeline. Gas may be re-injected or transported to shore in a separate pipeline. When feasible, the pipelines tie into other pipelines and do not have to go all the way to shore.

Bottom-supported platforms also may be made from steel-reinforced concrete. These are often used in the North Sea where the sea floor can better support such structures. This is not the case in the Gulf of Mexico because the soils are not as strong.

Production in Water Depths beyond 1,000 ft

The cost of conventional steel-jacket bottom-supported platforms increases very rapidly with increasing water depth, so in waters beyond 1,000 ft other alternatives are considered. These include compliant towers, tension leg platforms and floating production systems. Another option is subsea well completions with subsea production lines to platforms positioned in shallower waters.

Drilling Platforms

Compliant towers are partially bottom-supported platforms that can have built-in buoyancy chambers so that not all the weight is supported on the bottom. Generally these structures are much slimmer and more flexible than the conventional bottom-supported platforms; such structures have been designed to be used in water depths to about 3,000 ft.

Tension Leg Platforms are floating production structures that are tied to the seafloor by vertical steel pipes or “tendons.” These structures experience very little vertical motion but can move somewhat horizontally. One such structure is about to be installed at 2,860 ft in the Gulf of Mexico. In the case of this platform the wells were predrilled before installation of the platform itself; this reduces the time between installation of the platform and production. Researchers believe that tension leg platforms eventually will be used in water depths to 10,000 ft.

Floating Production Platforms are usually anchored to the sea floor with multiple mooring lines. Such platforms may be used for early production systems, allowing a project to commence production, perhaps directly into a moored tanker, while the permanent production facilities are being installed. Floating platforms also may be used on a longer term basis for production from smaller reservoirs, where the cost of permanent facilities cannot be justified. An advantage of floating platforms is that they can fairly easily be moved to another location when they are no longer required. The water depth limit for current designs is estimated to be around 6,000 ft.

Subsea Completions

Subsea Completions refers to wells drilled from floating drilling units. These wells are completed with production wellheads at the sea floor. They are then connected by subsea production lines to a nearby subsea collection point and from there to a platform. These multiphase pipelines (producing oil, gas and water together) can be several miles, perhaps tens of miles, away from the production platform. For reservoirs that are too small to support the cost of their own production platforms, subsea completions may be the answer. This is feasible if the production lines can reach an existing platform, or a platform specifically designed to receive production from a number of small, scattered reservoirs or wells. With the use of subsea completions, the wells themselves may be located in very deep water (perhaps 7,000 ft or more), whereas the production platform could be in much shallower water.

Subsea completions have been successfully used to depths of 2,562 ft offshore Brazil, and designs exist that can go to about 5,900 ft. At least 170 subsea completions have been installed offshore Brazil, with production going to fixed platforms in shallower water or to floating platforms.

The Texaco Deep Star Project will utilize subsea completions with very long production lines, up to 60 miles, to existing or new platforms that will be in 800 ft of water or less. Researchers expect this concept to make production possible from many small and medium-sized reservoirs in the Gulf of Mexico out to a water depth of about 6,000 ft. Participants in this joint industry project include most of the major oil companies in the U.S., many independents, and a variety of service companies and equipment suppliers.

Research in the Outer Continental Shelf

Research related to production from the deep water outer continental shelf is geared mostly towards making it financially possible to produce from reservoirs that are too small to support the high cost of separate production platforms with associated pipelines to shore.

One approach is the one mentioned above, to use subsea completions and produce to remote platforms located in relatively shallow waters. In many cases, the flow in these long lines will require pressure boosters in the form of subsea multiphase pumps. Before such pumps are available and reliable, a substantial amount of R&D will be required.

Cold subsea temperatures will in some cases result in the formation of hydrates and/or paraffin and asphaltene deposits. Better technology to prevent or remove such solids will be required. Subsea separators may be required to remove the water and thereby avoid formation of hydrates.

Another approach to making smaller reservoirs economical is to reduce the cost of deepwater platforms such as tension leg platforms. These platforms are generally designed to be constructed from steel or concrete. A substantial research effort is underway to construct the platforms, and also the tendons, from composite materials, such as fiberglass and graphite, combined with appropriate epoxies. This approach has the potential to reduce the weight significantly, possibly by a factor of four, and this in turn should reduce the overall cost. Different platform geometries are being evaluated in terms of the hydrodynamic and other forces acting on the structures. Extensive computer modeling is contributing to these designs.

Another exciting new technology being used extensively is the evaluation of 2-dimensional and 3-dimensional seismic data to find hydrocarbon reservoirs. With very extensive—and expensive—computer modeling and data processing, it is now possible to recognize petroleum reservoirs under 2,000-ft-thick layers of salt. Exxon has been demonstrated that it is possible to drill through these thick salt layers into the sub-salt reservoirs. Further application of this technology could significantly increase the reserves in the deepwater outer continental shelf.

Extended Reach and Horizontal Drilling

Research currently is being conducted in the areas of extended reach and horizontal drilling. Extended reach research may lead to longer reach from land and from platforms, and horizontal drilling may lead to higher production rates per well. Horizontal sections can now be drilled as long as one mile without much difficulty; the world record currently stands at about one and one-half miles. The research deals with the modeling and prediction of torque, drag, cuttings transport and buckling of tubulars. The results have general applicability wherever drilling is taking place.

Drilling for hydrocarbons is a relatively safe and well-understood process, but blowouts—flowing hydrocarbons to the surface out of control—still happen on occasion. More research should be done in this area to further improve safety.

2. Arctic Offshore

What makes the Arctic offshore unique in petroleum development is the presence of moving ice. This results in very high costs.

(a) Exploration Drilling

Most exploration drilling in waters to depths of about 50 ft has been accomplished from man-made gravel islands. At one time it was estimated that a gravel island would cost about one million dollars per ft of water depth. There are many exceptions to this "rule," but gravel islands are very expensive and essentially non-reusable. Also, in deeper waters the cost is much higher than the linear rule above suggests.

One approach to cutting costs while maintaining safety is to make the islands from man-made ice. Experiments were made with this approach in the mid-1980's. Following these experiments, at least two exploration wells were drilled successfully from ice islands that cost about one quarter as much as gravel islands in comparable water depths.

Another approach is to make the islands from steel or concrete and ballast them down with gravel and/or water. These islands have the advantage of being portable and therefore reusable. The water depth capability of these units can be extended by placing a gravel berm or a steel mat under the drilling structure.

Drilling from these structures is usually accomplished in winter, when the ocean is frozen over. During the winter the sea-ice typically grows to about 5 to 7 ft in thickness. Ice ridges caused by interaction between ice sheets, can be several times as thick. The ice moves around and can apply high forces to the drilling structures. In shallow waters (less than 50 ft), transportation to the rig is usually over grounded or floating ice roads during most of the winter.

In water depths of 100 ft or more, floating drilling vessels are used, either drillships or specially designed semisubmersibles. Drilling from floaters generally takes place during the two or three summer months of relatively ice-free waters. An existing Arctic semisubmersible is designed to extend the "summer" drilling season to about six months, with the help of ice breakers and ice-breaking supply ships.

(b) Hydrocarbon Production

In shallow waters, a few feet deep, production is currently accomplished from gravel causeways or fill, extending the shore out into the Arctic Ocean.

In spite of existing hydrocarbon discoveries, there is no current production in waters deeper than a few feet. In water depths to about 100 ft, we believe that production can be made to gravel islands or transportable steel/concrete structures like the ones discussed above for drilling exploration wells. Production wells could be drilled from enlarged versions of these islands or structures. Bringing the product ashore is more complicated.

Transportation of the crude could be accomplished via buried pipeline to shore, or by icebreaker tankers, or possibly through underground tunnels in the permafrost. All of these options are very expensive. Much more research is needed in this area.

In water depths beyond 100 ft, production structures have to be very large, strong and heavy, to resist the very high forces from moving ice. A number of such structures have been designed, but none of these have been built. In some areas, weak soils further complicate the designs.

Here again transportation of hydrocarbons to shore can be via buried pipeline or icebreaker tankers. Clearly, the costs will be very high.

Research related to production from the Arctic offshore has been going on for some time. During the 1980's a number of joint industry studies were conducted to determine when the ice freezes up in the fall, when it breaks up in the spring, and how it behaves in between. Several ice movement, ice thickness and ice strength studies were made. The purpose of these studies was to determine what ice forces the drilling and production structures would need to be able to withstand.

Some studies of this type are continuing, to determine how best to design the structures so that the ice breaks before the structures do.

Large ice chunks periodically break off from Ellesmere Island in the Canadian Arctic and float around in the Arctic Ocean for years and even decades. These floating ice islands or flowbergs can be several miles long and wide and present quite a hazard to structures, possibly including buried offshore pipelines. Studies are underway to monitor the movements of some of these flowbergs. Such monitoring is now being conducted via satellites.

Proprietary Research

In addition to the research and studies discussed above, there is no doubt that much proprietary research is going on within research laboratories. This research is not generally known and available, and much of it is likely to be site specific.

Because of the high cost of studies in the Arctic and the deep water outer continental shelf, such studies are usually carried out in joint industry projects. We will continue to see more of this, and also even more cooperation in the joint use of production and transportation facilities.

RESUME

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Educational Institutions

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Manager Technical Services, Gulf Mineral Resources Co., 1979-1983
Director Project Evaluation, Gulf Mineral Resources Co., 1978-1979
Director Special Projects, Gulf Mineral Resources Co., 1976-1978
Supervisor Production Engineering, Gulf Research & Development Co., 1973-1975
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Production Foreman, Mene Grande Oil Co., Venezuela, 1961-1963
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October 11, 1993

Mr. Solomon P. Ortiz
Chairman, Subcommittee on Oceanography,
Gulf of Mexico, and the Outer Continental Shelf
Room 1334 Longworth House Office Building
Washington, DC 20515-6230

Dear Mr. Ortiz:

I am happy to send you my reply to your question:

"Does deep water or frontier area drilling and production require any additional environmental safeguards? If there are any, what are your companies doing to address these safeguards? Has there been any research completed to address this issue?"

The major environmental danger lies in *not* developing the frontier areas. For every barrel of oil that is not produced in the United States one barrel of oil must be imported. This usually involves the use of tankers, which represent the largest source of pollution in our waters.

According to the National Academy of Sciences, offshore oil production accounts for less than two percent of all the oil in the world's seas and oceans, whereas marine transportation accounts for almost 46 percent. The Congressional Research Service in a 1990 report stated, " . . . The volume of oil spilled in U.S. waters will likely increase as tankered imported oil is substituted for OCS production."

A major hazard in drilling is **blowouts**. The U. S. drilling industry has an excellent drilling record, but blowouts still do occur, and more needs to be done to further reduce the risk of blowouts. (A blowout is an uncontrolled flow of formation fluids from a wellbore). According to the Minerals Management Service, from 1971 to 1991, 87 blowouts occurred during drilling operations on the Outer Continental Shelf. This corresponds to one blowout for each 256 wells drilled in search of hydrocarbons. It was also pointed out that most of the blowouts were of short duration, and since most of them were blowing gas, and not oil, there was relatively little pollution asociated with these blowouts..

Much research has been conducted on **well control to prevent blowouts.** Research is currently underway at several universities and research labs to develop computer models that can perform simulated blowouts, thereby helping us to learn more about this problem. Such models can be used to train drilling personnel to respond correctly when the danger signals of a possible blowout first occur. However, more research needs to be done in this area, especially regarding well control in very deep waters, but also in developing a better understanding of shallow gas blowouts.

Other areas of concern regarding frontier drilling and production include the effect of **mud slides and loop currents** on the outer continental shelf, and **ice movements** in the arctic. The impact of these natural phenomena on offshore platforms, wells and pipelines must be fully understood before facilities are installed. Both general and site specific evaluations are necessary, but this is well understood by the oil companies, and some such studies have been completed. It is the high cost of such studies and the resulting very high cost of installations that frequently make oil development in frontier areas uneconomic at current hydrocarbon prices. Tax or royalty relief would help to make some prospects economical.

By far the most effective way to spur U.S. production, reduce consumption and reduce oil imports is an **import fee** on all imported oil. This would have the beneficial effects of reducing pollution in the oceans and in the atmosphere, reducing our balance of trade deficit, and substantially reducing the federal budget deficit.

Sincerely,

Hans C. Juvkam-Wold

Hans C. Juvkam-Wold
Holt Professor of Petroleum Engineering

Testimony before the

U.S. House of Representatives
Committee on Merchant Marine and Fisheries
Subcommittee on Oceanography, Gulf of Mexico,
and the Outer Continental Shelf

Tuesday, September 14, 1993
2:00 P.M.
1334 Longworth House Office Building

Hearing on Proposed Legislation to Provide Incentives
to Explore, Develop, and Produce Natural Gas and Oil Resources
on Certain Areas of The Outer Continental Shelf

Panel II
Mr. Jim O'Sullivan
Manager, Brown & Root Seaflo

Summary

Gulf of Mexico oil producing reservoirs in deep water will have to perform better than fields on the shallower shelf in order to be economically viable. Development wells will have to produce at higher rates, and will have to drain larger reservoir volumes per well. With such improvements in reservoir performance, field developments in the 75 to 150 million barrel range can yield a rate of return of 15% before consideration of U.S. Federal Income Tax. However, individual operators may place a variety of other risk adjustments impacting the rate of return on these developments, especially in light of lower risk alternatives.

In the short term, technology developments will not greatly reduce the cost of deepwater developments. Existing technologies can be extended to develop fields in 5,000 to 6,000 foot water depths in the Gulf of Mexico. Current technology developments are addressing areas affecting approximately 25% of costs that make-up the total installed cost for a deepwater project. The success of these efforts in the short term can reasonably reduce these costs by another 25%.

Introduction

The following comments result from an in-house Brown & Root examination of deepwater development prospects (i.e., beyond diver depth of 1,000 ft). Specifically, we wanted to know: what drove development economics in general; what drove them specifically in the Gulf of Mexico (GOM); and what areas of capital cost held the most potential for improving development economics. The examination was done separately for oil and gas developments, with only the oil case presented here. We hope the discussion will serve as a useful framework for viewing development economics and technology trends.

The analysis made use of the SEAPLAN computer program. This program is an expert system that can identify, conceptually define, and economically compare technically feasible approaches for developing offshore oil & gas fields. The code logic and cost database are updated twice a year as part of the maintenance program for the 16 international oil operators who have licensed the program. We feel the program's sizing logic and cost data base create system descriptions representative of developments being planned in the deepwater GOM.

Economic Drivers

This section addresses what operators can afford to pay for deepwater GOM developments. Areas considered are: what economic criteria GOM operators use to decide whether to proceed with projects; and, what value operators put on hydrocarbon reserve estimates in the ground.

The discussion begins with an examination of the return on operating capital of 17 GOM operators representing a range of company sizes. The return on operating capital is based on financial data from each company's annual reports over the last five years. We used this measure as a reasonable estimate of each company's project "hurdle rate," that is, the rate of return on investment required for project approval.

There are many definitions of return on operating capital. We defined the sources of capital as operating revenue minus point-of-sale excise tax (e.g., gasoline tax), plus sale of assets. Uses of capital included both capital and operating expenditures for upstream and downstream operations in both foreign and domestic operations (i.e., all alternative operating uses of capital). Federal income taxes were *not* included as uses of capital, nor were depreciation expenses, corporate overheads, or financial costs (i.e., interest or dividends).

The summarized results, shown in Figure 1, indicate an average rate of return for the industry of approximately 16%. This agrees with the often stated internal project hurdle rate of 15% before income tax. In the following present value analyses we used 15% before tax as the discount rate.

Next, we estimated the capital cost an operator can afford to spend to develop a field. This is expressed as the present value of the reserves in the ground per barrel of recoverable reserves, and is equal to the discounted sum of the fraction of recoverable reserves produced per year, multiplied times the price of oil forecasted that year. In the following discussion, this value is referred to as the present value of reserves.

For this analysis, a price of $20/B (i.e., $20 per barrel of produced oil) was forecasted to remain constant into the future (i.e., no price escalation). We assumed that gas separated from produced oil was reinjected to help maintain initial production rates and to eliminate the capital cost of gas pipelines. Also, an average operating expense of $3/B was considered, though this will be a function of technology used, pipeline tariffs, etc.

The present value of reserves is a function of initial production rate, reserve size, rate at which wells are brought on-stream, price forecast, and discount rate. The last two variables have been set for the current study. The following discussion examines the influence of the other three variables.

Reserve size has a linear relationship with the present value of reserves. It is not greatly influenced by the number of wells used to develop the field. This is demonstrated in Figure 2 which shows the present value of reserves on the vertical axis, recoverable reserves on the horizontal axis and a set of curves representing a range of reserves per well (i.e., amount of oil eventually produced by each production well). For the same range of reserves per well, smaller fields are produced faster and therefore have a higher present value per barrel of recoverable reserves. Also, smaller fields show a diminishing return for increasing well count because the life of an individual well decreases to the point where the production from initial wells drilled starts to decline before the last wells are drilled.

A similar result is seen in Figure 3 where the initial production rate is varied for a fixed reserve size. Note that the set of curves depicting reserves per well show the same diminishing return as more wells are added to a reserve of a given size.

There are several points to make regarding these graphs. First, a good performing GOM well on the shelf can produce 2,000 B/D (i.e., barrels of oil produced per day) and drain around 3 MMB/W (millions of barrels per producing well). Geologists are expecting reservoirs in deep water to have thicker net pay zones. This should mean more drainage volume per well and higher production rates than encountered on the shelf. A rate of 3,000 B/D is considered in the following analyses, giving a development cost constraint of $6.50/B (Figure 3). Next, though reserve size per well is not a very important factor in the present value of reserves, it becomes important when the costs are considered for drilling and processing the production from those wells. Finally, because of the general assumptions used, this present value analysis is applicable to other areas of the world, not just the GOM.

Figure 4 shows the effect of discount rate on the present value of reserves. An important point to recall from Figure 1 is that certain operators are enjoying returns on operating capital higher than 15%. Such alternative investment opportunities may drive those operators away from a GOM development while other operators would find the same development very attractive.

A final factor influencing the present value of reserves in the ground is the rate at which you drill and complete (D&C) wells. Figure 5 shows the effect of D&C times. Note the above analysis used 6 wells per year. The rate of well D&C is a function of well depth (i.e., reservoir depth and well spacing), number of rigs operating and learning curve effects. Deepwater GOM fields tend to be have deep reservoirs, typically around 10,000 ft to 15,000 ft below the sea surface. Initial development wells can take 3 months to D&C (i.e., 4 per year). However recent deepwater drilling results have shown the effect of the learning curve wherein D&C times on the final wells dropped by a factor of 2.

A rate of 2 months per well (i.e., 6 per year) was assumed as an indicative value. A single rig was assumed for the development and comparison of capital costs.

<u>Development Costs</u>

This section examines representative Total Installed Costs (TIC's) for deepwater GOM developments. The SEAPLAN computer program was used to generate TIC estimates for new installation production systems that differed by numbers of wells, water depth and distance from existing infrastructure such as pipelines that can accept a sales quality crude oil.

SEAPLAN was used to select the most economical technology for each case from among a range of available technologies: Conventional Fixed Platform (CFP); Compliant Piled Tower (CPT); Tension Leg Platform (TLP); and a Floating Production System (FPS). Floating Production, Storage and Offloading (FPSO) systems were not considered since they introduce shuttle tanker transportation rather than a pipeline; such an analysis can be done as a follow-on study. Also, newer, novel approaches such as spar buoy systems have not yet been considered, but could be later.

A new-build semisubmersible vessel was considered for the FPS cases. Operators have, and are currently, converting semi-submersible drilling units into FPS vessels. There are two reasons for the new-build choice for this analysis: the aging of the existing fleet of available vessels, and the utilization of the younger vessels as drilling units. The majority of vessels in the existing semisubmersible drilling fleet are older than their original design life. Conversion to a deepwater FPS will be very expensive, with the expense increasing each year. Also, the newer rigs are in demand for drilling and few new rigs are being built because current day rates do not support new construction. The window of opportunity for conversion to FPS's is closing.

The resulting Total Installed Costs (TIC's), shown in Figure 6, form a relatively consistent set of curves for different numbers of wells over a range of water depths and production system technologies. Since each well is initially producing 3,000 B/D, the capacity of the process facilities is constant for each assumed well count. One water injection well is assumed for each four producing wells, and one gas injection well is assumed for each 10 producing wells. Note that Figure 6 shows only the producing wells.

Different operators have different risk perceptions regarding deepwater GOM developments. They may impose risk adjustments such as cost multipliers for specific cost categories (e.g., 20% contingency for offshore construction), or require a higher overall project hurdle rate (i.e., same effect as a single cost multiplier over all cost categories). The risk adjustment factors would probably increase with increasing water depth. For the purposes of this study, no risk contingencies were considered.

The type of production system technology changed over the range of water depths considered. Figure 7 presents a general indication of the applicable water depth and well count ranges for each technology as determined in the SEAPLAN parametric study. Note that the demarcation lines shown indicate where competing technologies have comparable economies. The actual overlap of comparability may extend beyond just a single line. Also, operator preferences will impact the final choices, especially where no technology shows a clear economic advantage.

In order to determine what systems will generate the 15% before tax return threshold, the \$6.50/B development cost constraint was applied to the TIC results. Figure 8 is the same as Figure 6 with a range of reserve sizes shown on the right hand vertical axis that are directly linked to the TIC values on the left axis by the \$6.50/B multiplier. Recall that the \$6.50/B constraint correlates to 200 MMB recoverable reserves at 3,000 B/D initial well production rate. The results in Figure 8 will over estimate reserve requirements for reserves less than 200 MMB and production rates greater than 3,000 B/D.

The combination of reserve sizes and well counts in Figure 8 creates a set of curves representing lines of constant reserves per well (i.e., reserve size divided by well count equals reserves per well). Along each such line, the combination of water depth, well count, and reserve size should generate a 15% before tax return. To the left of each curve, the same combination of water depth and reservoir size would generate greater returns while those to the right would generate lower returns.

Another way to interpret Figure 8 is to consider that for a given water depth, there are a number of economically viable systems depending on how much oil can be drained from each well. The larger the drainage volume per well, the fewer the development wells and the smaller the processing capacity that will be required, and the more viable the development.

Note that a different $/B TIC constraint can be substituted to reflect a different production rate (Figure 3), a different hurdle rate (Figure 4), a different drilling rate (Figure 5), or a combination of the above. Also, a new set of curves can be constructed for a different reserve size (Figure 2).

The above analysis indicates that fields in the 75 MMB to 150 MMB range warrant development, even in very deep water. These results confirm the contention of other authors that deepwater reservoirs must produce better than those on the GOM shelf. Operators proceeding with developments today believe production rates will be in the range of 3,000 B/D and higher, with reserves per well of 5 MMB/W or higher.

Cost and Technology Trends

The TIC of a development can be divided into three broad cost categories: the drilling and completion (D&C) of the wells; the production system; and the transportation system that brings the product back to existing infrastructure. Technology and commercial factors will influence the future economic trends in each of these cost categories.

Figure 9 shows the TIC breakdown for the same well count and production rate in two water depths and two offset distances (i.e., length of pipeline). The 2,000 ft systems are both CPT's. The 4,000 ft systems are both FPS's though TLP systems would be comparable since a new-build hull is assumed for the FPS.

D&C costs are a function of the number, depth and spacing of wells (geological factors), lease rate of the drilling rig (commercial factor), and drilling rate (technological factor). The rate of drilling impacts both development costs and the present value of reserves in the ground (i.e., what costs you can afford). Operators have already incorporated improved drilling technologies in order to optimize their drilling program. Only incremental improvements can be anticipated in drilling rates in the near term.

All the deepwater development scenarios assumed that the drilling the initial wells were drilled with a leased floating drilling unit prior to the arrival of the permanent production facilities. The cost of this unit is a major contributor to D&C costs. However, the day rate (i.e., lease cost) charged for these rigs is already below the rate required to replace such a unit given the current costs of rig construction. The point to consider here is that day rates on deepwater floating drilling units are not likely to come down, and will probably go up in the long term as replacement rigs are required.

The transportation cost category, shown in Figure 9, varies with pipeline length as would be expected. With the advent of technologies such as "J Lay", the methods and equipment exist to lay long deepwater pipelines. Cost saving improvements will evolve, such as faster pipe joining techniques, but the basic technologies exist today.

The limited worldwide demand for deepwater pipeline construction services has limited their supply. The unit costs of these services can not be expected to decline until greater demand occurs, especially local demand that warrants the long-term local deployment of competing deepwater construction vessels.

The last TIC category is production systems. Figure 10 shows a further breakdown of the production system costs for the 4,000 ft water depth/50 mile offset case from Figure 9. The production system in this case is an FPS and represents approximately 48% of the TIC, or about $3.12/B for the $6.50/B base case. The topsides facilities (i.e., process and auxiliary systems) represent 24% of the production system (i.e., 12% of TIC). They are primarily a function of process capacity, and would not change greatly whether on a CPT or TLP. Technology developments will not greatly impact the process facility category.

The subsea facilities represent seafloor equipment and the systems required to operate that equipment. In this example, they represent 29% of the production system (i.e., 14% of TIC). Technology development in this category revolves around improving reliability and maintenance methods, as well as reducing initial capital costs. One area of significant cost reduction is leasing rather than purchasing maintenance equipment. Due to efforts such as DeepStar, the operators are moving towards common design features that allow reuse of maintenance equipment among several operators' fields. This and other improvements may reduce subsea facilities costs about 10%, or about $.09/B for the $6.50/B base case.

The final cost category is where there is a great deal of technology development and rethinking the problem in general. The platform facilities comprise all systems that support the topside facilities and connect them to the producing wells and the export transportation systems (i.e., pipeline). The category represents 47% of the production system cost, or 23% of the TIC, and represents about $1.47/B for the $6.50/B base case. Examples of some approaches being considered to reduce this cost are:

- Building a shallow water platform (i.e., low cost) for topside facilities, with minimal, or no, topside facilities at the field site.

- Using floating vessels such as the spar buoys that represent less total steel weight than alternative systems in deep water.

- Converting existing marine equipment; this was already discussed but is mentioned again because there will be specific opportunities that can be exploited.

The level of cost reduction resulting from any of these technological developments is hard to quantify. The potential exists to impact the platform facility area by about 25%, or about $.37/B in the $6.50 base case.

Finally, a significant way of reducing the TIC is to use existing process facilities on a neighboring platform. This is generally called a tie-back approach, and can eliminate, or greatly reduce, the production system costs without adversely effecting the D&C and transportation costs. There are technology developments involved in this area, some of which are being pursued in the DeepStar program. However, a tie-back approach may delay development of certain deepwater fields until processing capacity becomes available.

Average Alternative Investment Opportunity

17 Major GOM Operators

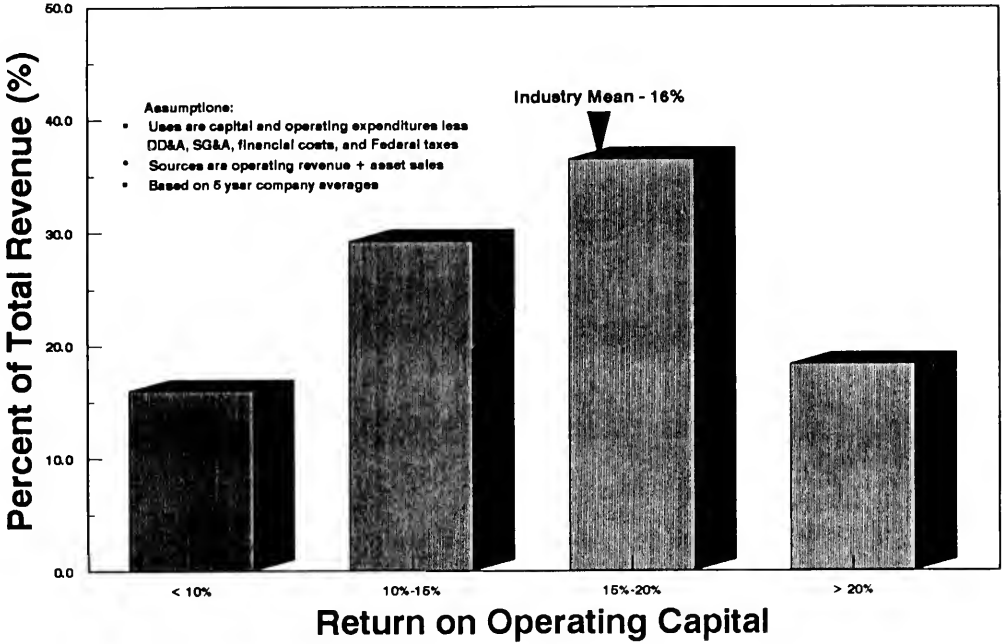


Figure 1

Present Value of Oil in the Ground

(Function of Reservoir Size)

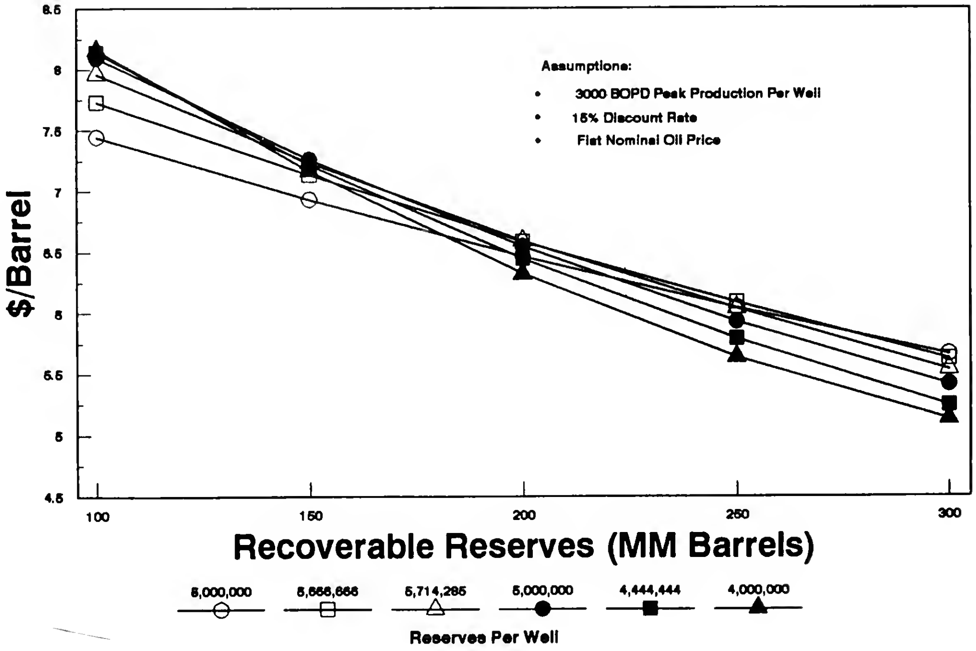


Figure 2

Present Value of Oil in the Ground
(Function of Production Rate)

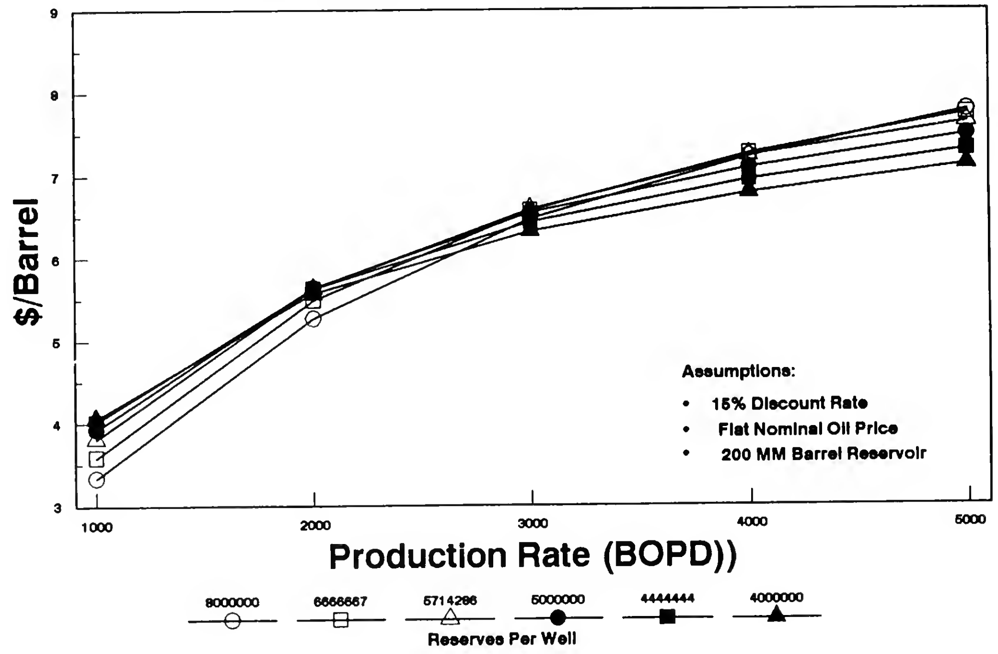


Figure 3

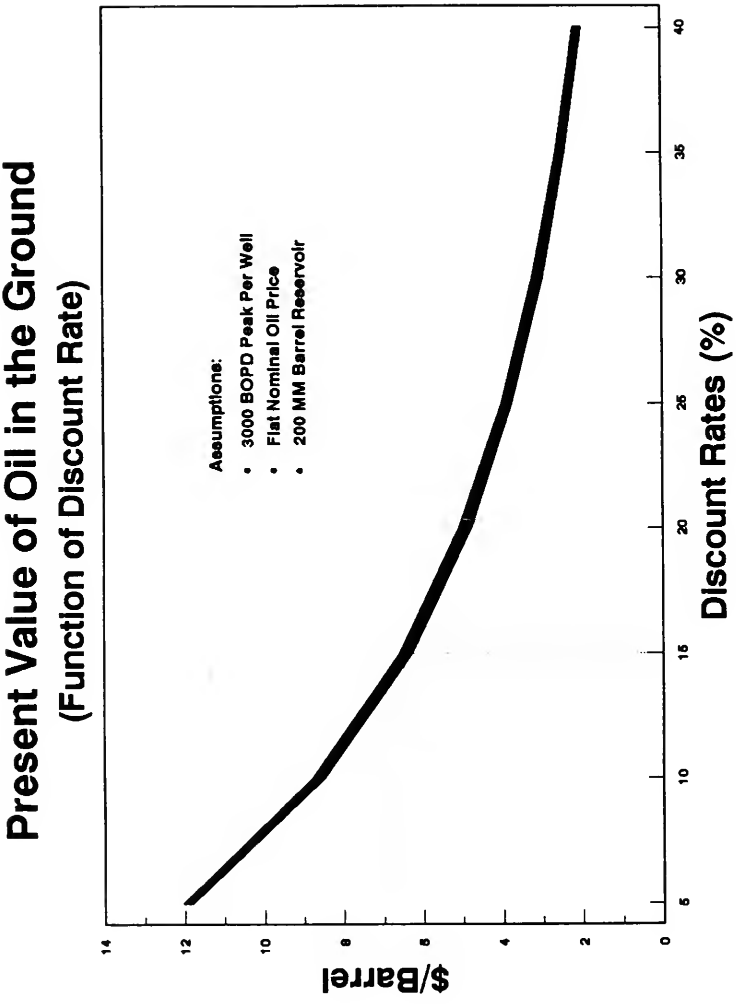

Present Value of Oil in the Ground
(Function of Discount Rate)
Assumptions:
• 3000 BOPD Peak Per Well
• Flat Nominal Oil Price
• 200 MM Barrel Reservoir
$/Barrel
0
2
4
6
8
10
12
14
5
10
15
20
25
30
35
40
Discount Rates (%)

Figure 4

Present Value of Oil in the Ground
(Function of Drilling & Completion Time)

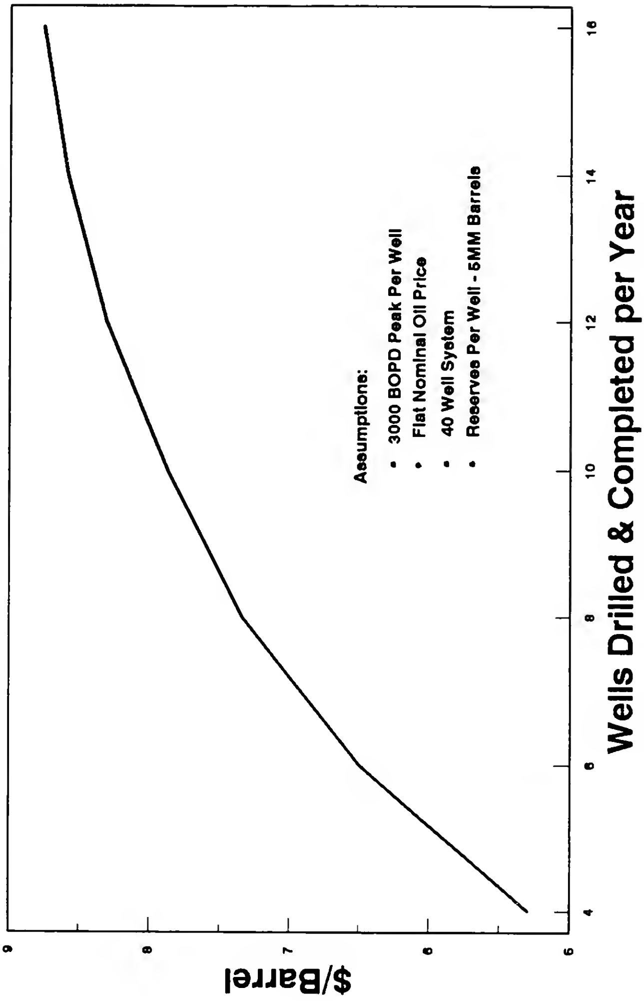
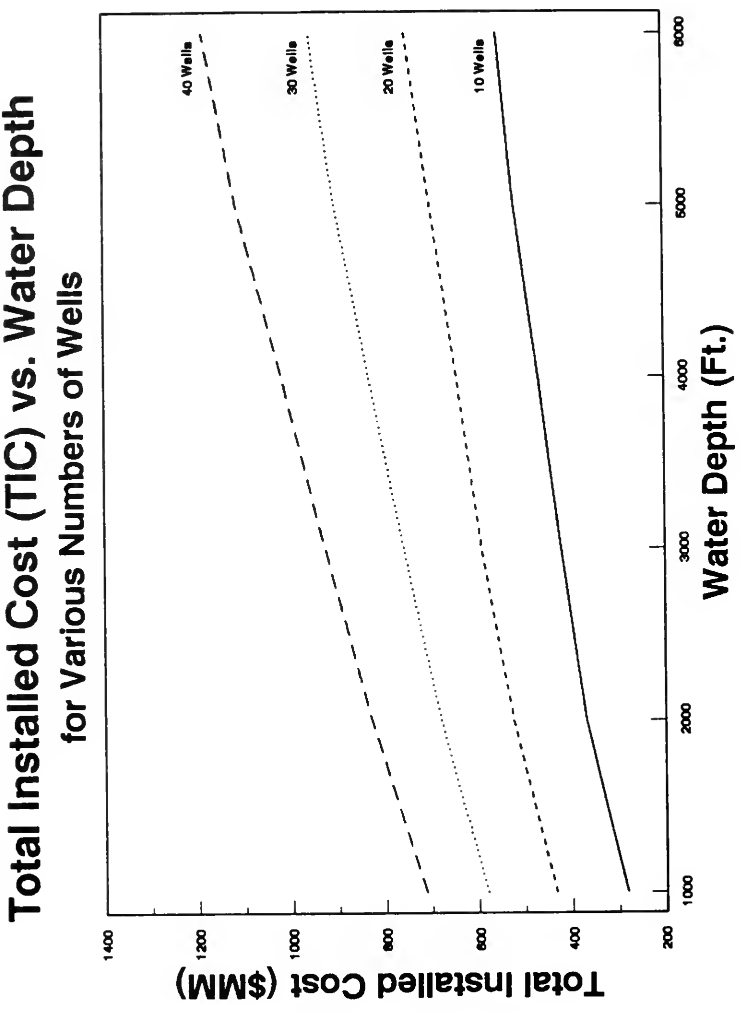
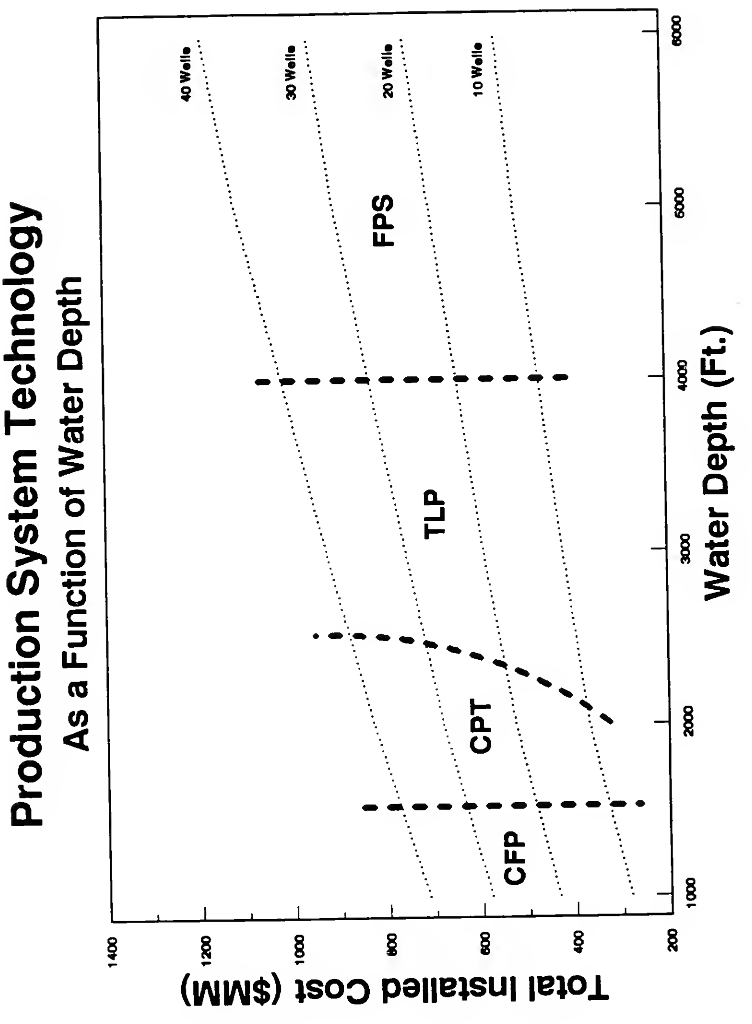


Figure 5



Total Installed Cost (TIC) vs. Water Depth
for Various Numbers of Wells
40 Wells
30 Wells
20 Wells
10 Wells
Total Installed Cost ($MM)
200
400
600
800
1000
1200
1400
Water Depth (Ft.)
1000
2000
3000
4000
5000
6000

Figure 6



Production System Technology
As a Function of Water Depth
Total Installed Cost ($MM)
1400
1200
1000
800
600
400
200
Water Depth (Ft.)
1000
2000
3000
4000
5000
6000
40 Wells
30 Wells
20 Wells
10 Wells
CFP
CPT
TLP
FPS

Figure 7

$6.50 / Barrel TIC Constraint
For Various Reserves Per Well

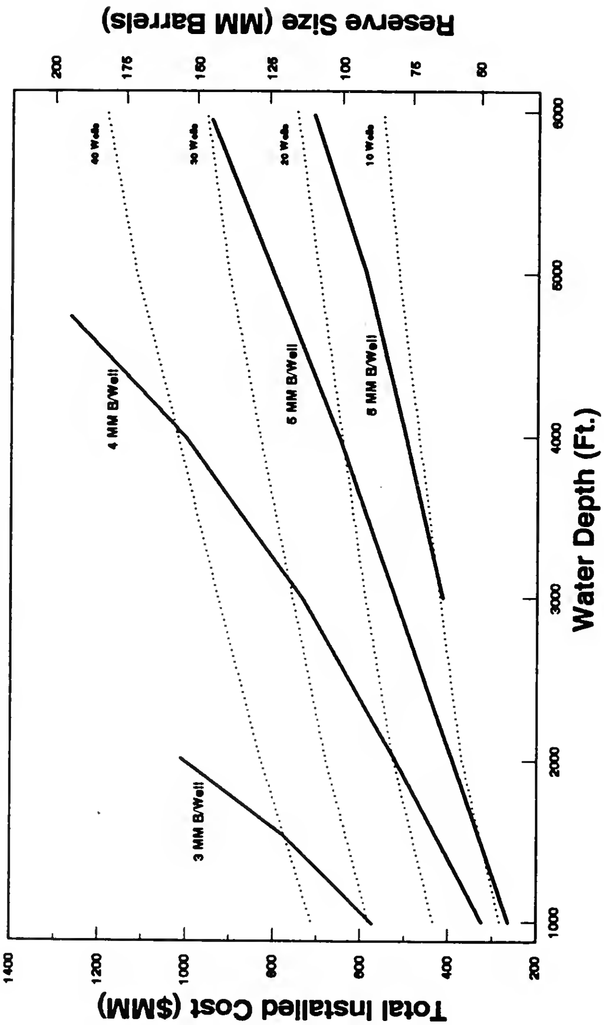


Figure 8

Total Installed Cost Categories

(30 Producing Wells @ 3000 B/D)

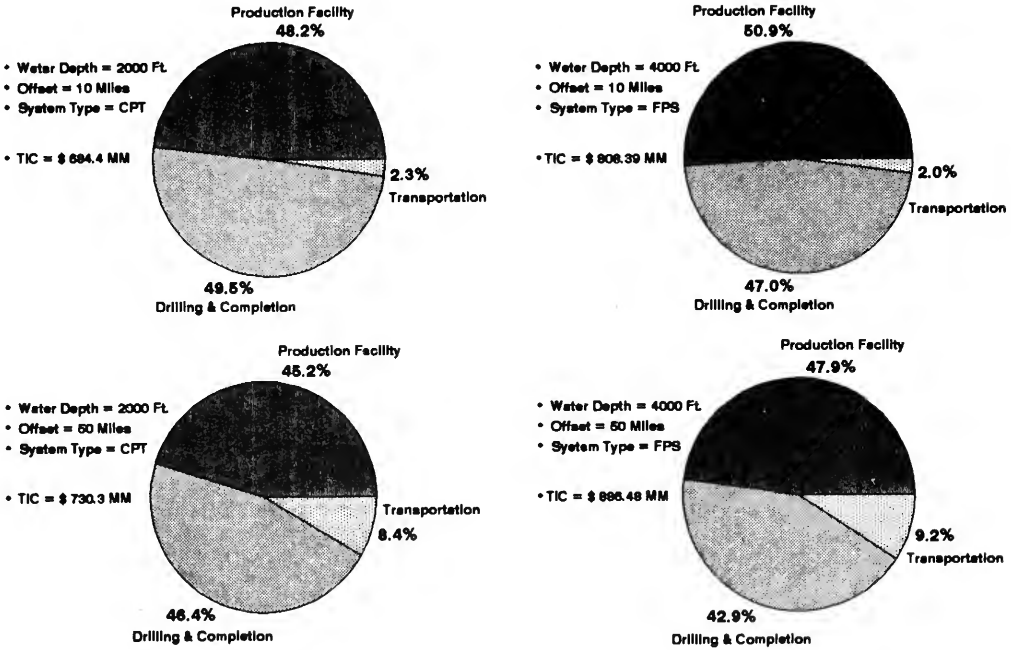


Figure 9

Production Facility Cost Categories

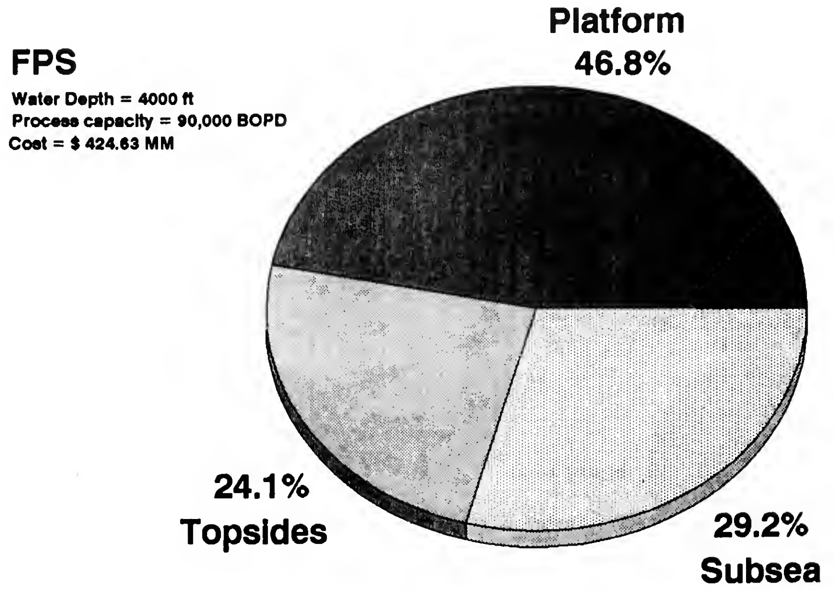


Figure 10

Brown & Root Seaflo

Post Office Box 4574
Houston, TX 77210-4574

October 29, 1993

Honorable Solomon P. Ortiz
U.S. House of Representatives
Committee on Merchant Marine and Fisheries
Room 1334, Longworth House Office Building
Washington, D.C. 20515-6230

Subject: Hearing on Offshore Oil and Gas Incentives RE:HR 1282

Dear Chairman Ortiz:

The following is our response to the questions your subcommittee asked in regards to the above reference hearing. The answers pertain specifically to the engineering and construction phase of an offshore development.

<u>Does deep water or frontier area drilling and production require any additional environmental safeguards?</u>

We are aware of one environmental safeguard that is required by current regulation for drilling and construction operations in deep water that is additional to what is done in shallow water: protection of chemosynthetic communities on the seafloor. The Mineral Management Service regulations on this matter are given in NTL 388-11 which became effective February 1, 1989. These regulations specify "..measures to detect and protect deepwater chemosynthetic communities" in water depths greater than 400 m (i.e., deep water).

<u>If there are any, what are your companies doing to address these safeguards?</u>

In water depths less than 400 m, equipment such as a side scan sonar and a sub-bottom profiler use acoustic methods to identify features on the seafloor and just below the seafloor. Acoustic methods of survey currently lack the resolution required to conclusively identify seafloor features. When a feature is thought to pose a potential hazard to pipelines, platforms or mooring anchors, further investigations may be conducted by divers or Remotely Operated Vehicles (ROV's) using optical camera equipment to take pictures in order to conclusively identify the feature.

The NTL 388-11 regulations require, in water depths greater than 400 m, conclusive identification of all seafloor features that could be disturbed by operations related to the drilling and production of oil & gas reserves in order to determine the possible presence of chemosynthetic communities. In practice this means features identified by traditional bottom survey methods (e.g., side scan and sub-bottom profiler) must be further investigated by ROV's using optical camera equipment to make sure no chemosynthetic communities are present. If such communities are deemed present, pipelines, foundations and mooring anchors are carefully located elsewhere. The current regulation causes the additional expense for ROV survey's of seafloor features that would otherwise not pose a danger to the production operation.

Has there been any research completed to address this issue?

The industry is continually improving the quality of both acoustic and optical survey equipment. For example, underwater laser systems are becoming available that provide better optical resolution of seafloor features. Also, experience will lead to more precise interpretation of acoustic survey records regarding the presence of chemosynthetic communities.

I hope the above information is of assistance to you in your hearings. Brown & Root/Halliburton continues its technology research aimed at the offshore industry's needs for cost effectiveness, environmental protection, and human safety.

Sincerely,

James F. O'Sullivan
Manager, Brown & Root Seaflo

TESTIMONY OF

MYRON J. RODRIGUE

VICE PRESIDENT AND GENERAL MANAGER

AKER GULF MARINE

BEFORE THE

OCEANOGRAPHY, GULF OF MEXICO AND OCS SUBCOMMITTEE

MERCHANT MARINE AND FISHERIES COMMITTEE

SEPTEMBER 14, 1993

**TESTIMONY OF
MYRON J. RODRIGUE
VICE PRESIDENT AND GENERAL MANAGER
AKER GULF MARINE
BEFORE THE
OCEANOGRAPHY, GULF OF MEXICO AND OCS SUBCOMMITTEE
MERCHANT MARINE AND FISHERIES COMMITTEE
SEPTEMBER 14, 1993**

Good afternoon Mr. Chairman and members of the Subcommittee. I appreciate the invitation to testify. My name is Myron J. Rodrigue. I am Vice President and General Manager of Aker Gulf Marine, a Texas general partnership. We operate two fabrication yards, located in Ingleside and Aransas Pass, Texas, to service the offshore oil and gas industries.

Our company is a relative new comer to the industry. In 1984, our parent company, Peter Kiewit Sons', Inc., investigated the offshore fabrication market and determined that development of the OCS was an area which would experience growth and a need for additional capacity for deep water platform construction.

After opening our doors in November of 1984, we secured a contract to fabricate Mobil's Green Canyon Block 18 structure. At the same time, we formed a joint venture with a West Coast firm to bid Shell's Bullwinkle structure. This joint venture was successful in securing the contract. Fabrication of Bullwinkle, to date the world's largest fixed offshore structure, began in the summer of 1985. This project took three years to build. Together with the Mobil job and several smaller projects, our total employment reached 1200. If we include subcontractors working directly for us and our clients, total employment at our facilities was over 1600. The point is that initiatives for offshore development mean jobs for the United States.

I became Vice President and General Manager in December 1987, just six months before loadout of the Bullwinkle structure. At that time, our total craft employment was down to approximately 200.

During my first two years as General Manager, my priorities were quite diverse. One was to determine the lowest cost option to shut down our business. This was a charge from our upper management. Another was to secure new work to keep our business going.

As you can see from the attached historic manpower graph, our business is quite cyclical. It is quite difficult to justify the capital investment required to service the deep water sector of the offshore industry when the market is so unpredictable. This unpredictability is not because our clients are unwilling to explore and develop our resources.

We have invested over 50 million dollars in our plant and equipment, almost all of this in the first three years. Because of the unique construction required for these platforms, we have also spent a great deal of time and money training a work force capable of producing the quality levels expected by our clients.

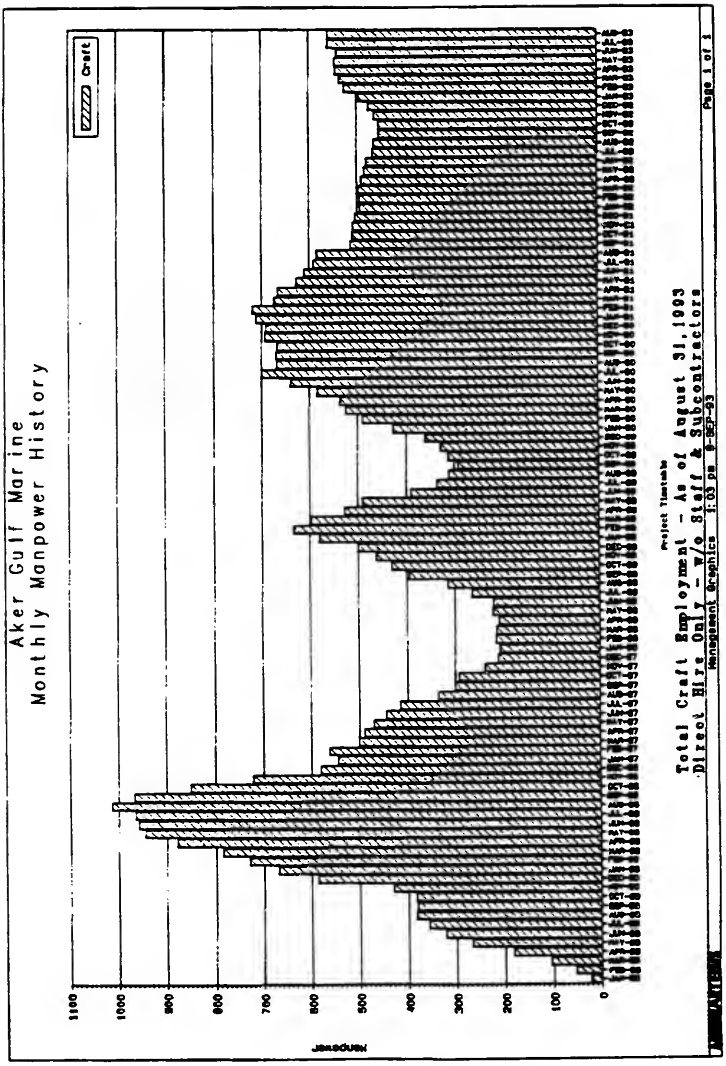
As noted earlier in Mr. Stewart's testimony, our industry has lost 450,000 jobs in the past decade. If you consider the Bullwinkle project alone, it created an average of 600 jobs over three years for us in South Texas. Additionally, direct project procurements were made in 33 of the 50 states as shown on the attached drawing. When the expenditures of our indirect suppliers are considered, undoubtedly the economic impact touched almost every state in the union. A predictable OCS development will produce jobs across the United States, jobs that are not just local to the coastal states.

Deep water development is not only good for reducing our independence on imported energy, it is definitely without a doubt job-creating and economically stimulating.

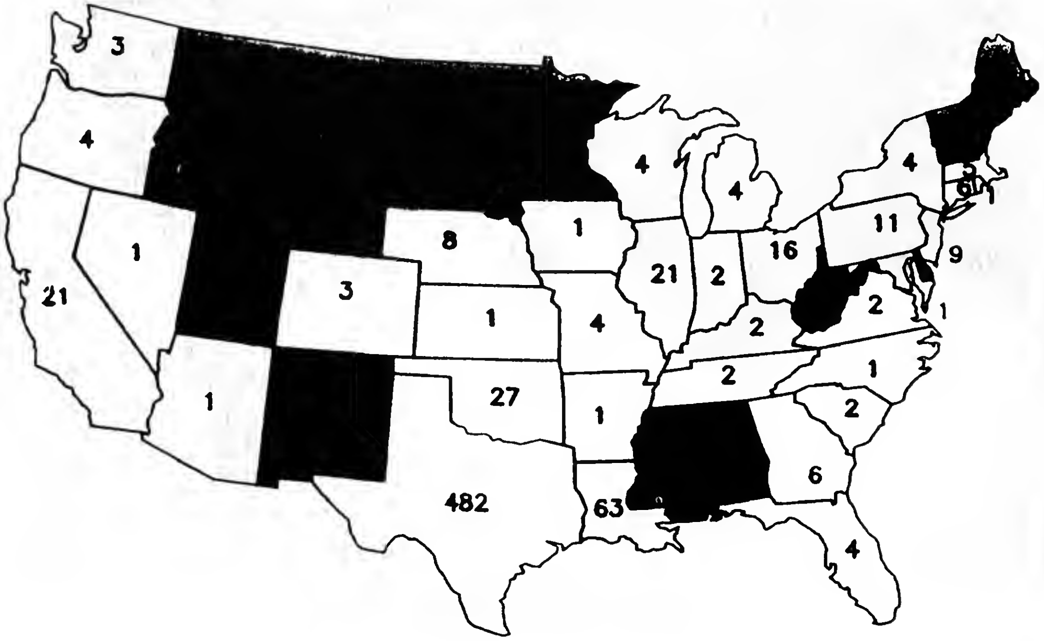
We need positive, secure, uninterrupted incentives to allow long-term exploration and development to stimulate an industry which can be productive and a positive influence on the security and standard of living of the American people.

In closing, the petroleum industry can provide our nation's domestic energy requirements. Producing this domestic energy will strengthen our economy by generating new jobs, allowing the return to work of those trained workers who lost their jobs during the past decade, stemming the flow of dollars to buy foreign energy, and creating additional revenues for the federal treasury. At the same time, it will help President Clinton meet his objectives of increasing the use of natural gas for its environmental benefits and as a means of reducing our use of foreign petroleum.

Thank you for hearing my testimony.


Aker Gulf Marine
Monthly Manpower History
Craft
Manpower
0
100
200
300
400
500
600
700
800
900
1000
1100
Project Timetable
Total Craft Employment - As of August 31,1993
Direct Hire Only - W/o Staff & Subcontractors
Management Graphics 1:03 pm 8-SEP-93
Page 1 of 1

BULLWINKLE CONSTRUCTORS / SOI VENDORS



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103D CONGRESS
1ST SESSION

H. R. 1282

To provide enhanced energy security through incentives to explore and develop frontier areas of the Outer Continental Shelf and to enhance production of the domestic oil and gas resources in deep water areas of the Outer Continental Shelf.

IN THE HOUSE OF REPRESENTATIVES

MARCH 10, 1993

Mr. FIELDS of Texas (for himself, Mr. TAUZIN, Mr. YOUNG of Alaska, Mr. LIVINGSTON, and Mr. LAUGHLIN) introduced the following bill; which was referred jointly to the Committees on Natural Resources and Merchant Marine and Fisheries

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A BILL

To provide enhanced energy security through incentives to explore and develop frontier areas of the Outer Continental Shelf and to enhance production of the domestic oil and gas resources in deep water areas of the Outer Continental Shelf.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

SECTION 1. SHORT TITLE.

This Act may be cited as the "Outer Continental Shelf Enhanced Exploration and Deep Water Incentives Act".

SEC. 2. AMENDMENTS TO THE OUTER CONTINENTAL SHELF LANDS ACT.

(a) INCENTIVES.—Section 8(a)(3) of the Outer Continental Shelf Lands Act (43 U.S.C. 1337(a)(3)) is amended to read as follows:

"(3)(A) The Secretary, at his own discretion or on petition of a lessee, in order—

"(i) to promote development and new production on producing or nonproducing leases, through primary, secondary, or tertiary recovery means; or

"(ii) to encourage production of marginal or uneconomic resources on producing or nonproducing leases, which may include the use of primary, secondary, or tertiary recovery means,

may reduce, suspend, or eliminate any royalty or net profit share set forth in the leases. In the case of a petition of a lessee, the Secretary shall make a final determination under this subparagraph within 6 months after the submittal of such petition.

"(B)(i) Notwithstanding any other provision of this Act, except as provided in clauses (ii) and (iii) of this subparagraph, no royalty payment shall be due on new production from any lease located in water depths of 200 meters or greater until the capital costs directly related to such new production have been recovered by the lessee out of the proceeds from such new production.

"(ii) Notwithstanding clause (i), in any month during which the arithmetic average of the closing prices for the earliest delivery month on the New York Mercantile Exchange for Light Sweet crude oil exceeds $28.00 per barrel, any production of oil described in clause (i) shall be subject to royalties at the lease stipulated rate.

"(iii) Notwithstanding clause (i), in any month during which the arithmetic average of the closing prices for the earliest delivery month on the New York Mercantile Exchange for natural gas exceeds $3.50 per million British thermal units, any production of natural gas described in clause (i) shall be subject to royalties at the lease stipulated rate.

"(iv) The prices referred to in clauses (ii) and (iii) of this subparagraph shall be changed during any calendar year after 1993 by the percentage if any by which the consumer price index changed during the preceding calendar year, as defined in section 111(f)(4) of the Internal Revenue Code of 1986.

"(v) Nothing in this subparagraph shall be construed to affect any requirement under this section to pay bonus bids.

"(vi) For purposes of this subparagraph—

"(I) the term 'capital costs' shall be defined by the Secretary, shall include exploration costs incurred after the acquisition of the lease and development and capital production costs directly related to new production, shall not include any amounts paid as bonus bids or paid as royalties pursuant to clause (ii) or (iii), and shall be adjusted to reflect changes in the consumer price index, as defined in section 111(f)(4) of the Internal Revenue Code of 1986; and

"(II) the term 'new production' means any production from a lease from which no royalties have been due on production, other than test production, prior to the date of the enactment of the Outer Continental Shelf Enhanced Exploration and Deep Water Incentives Act, or any production resulting from lease development activities under a development and production plan approved by the Secretary under section 25 after the date of the enactment of the Outer Continental Shelf Enhanced Exploration and Deep Water Incentives Act.".

(b) FRONTIER AREAS.—Section 18 of the Outer Continental Shelf Lands Act (43 U.S.C. 1344) is amended by adding at the end the following new subsection:

"(i) The Secretary shall, in each leasing program prepared under this section, designate as frontier areas portions of the outer Continental Shelf, if any, with respect to which the Secretary will exercise authority under section 8(a)(3)(A) to reduce, suspend, or eliminate the requirement to pay royalties. Any such designation shall include a full description of the terms of such reduction, suspension, or elimination. In designating frontier areas under this subsection, the Secretary shall take into consideration the increased capital costs associated with exploration and development in coastal or marine environments, including arctic environments, with special environmental protection requirements.".

SEC. 3. REGULATIONS.

(a) INCENTIVES.—The Secretary shall, within 180 days after the date of the enactment of this Act, issue such rules and regulations as are necessary to implement the amendment made by section 2(a).

(b) FRONTIER AREAS.—The Secretary shall, within 1 year after the date of the enactment of this Act, issue regulations defining the term "frontier area" for purposes of carrying out section 18(i) of the Outer Continental Shelf Lands Act.

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PREPARED STATEMENT
OF
SHELL OIL COMPANY

On the Outer Continental Shelf Enhanced Exploration and Deepwater Incentives Act, H.R. 1282

Before the U.S. House of Representatives Oceanography, Gulf of Mexico, and the Outer Continental Shelf Subcommittee
of the
Committee on Merchant Marine and Fisheries

September 14, 1993

For further information, please contact:

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PREPARED STATEMENT
OF
SHELL OIL COMPANY

Mr. Chairman and Members of the Subcommittee:

Shell Oil Company, on behalf of its two domestic exploration and production subsidiaries, Shell Offshore Inc. headquartered in New Orleans, Louisiana and Shell Western E&P Inc. headquartered in Houston, Texas, appreciates this opportunity to present its views in support of H.R. 1282, the Outer Continental Shelf Enhanced Exploration and Deepwater Incentives Act, which would provide a royalty holiday until investment costs are recouped for projects in 200+ meters (656+ feet) of water.

A major focus of Shell's exploration and production activities is in the domestic offshore, particularly the Gulf of Mexico, where we have been producing since the 1940's. Shell holds interests in over 1,000 Gulf of Mexico tracts and is one of the largest leaseholders in the Gulf of Mexico. In addition, we have produced more hydrocarbons than any other company in the Gulf of Mexico -- almost two billion barrels of oil and ten trillion cubic feet of natural gas through 1990, or 13 percent of the total hydrocarbons produced. Technology has been the key to this performance. Recent advances in seismic acquisition and processing technology coupled with expertise in integrated interpretation have allowed us to find and delineate hydrocarbon accumulations with greater accuracy than ever before. These technology advances, particularly three- dimensional seismic techniques, have led to a re-evaluation of many producing fields along the continental shelf. Some exploratory and redevelopment work has already taken place in this area. Further re-evaluation along the shelf is anticipated in the future.

In addition, Shell's long-term commitment to the development of leading edge deepwater drilling and structural engineering technology has allowed us to take a lead role in the deep and ultra-deep waters of the Gulf of Mexico, setting numerous drilling and production records in the process. These technology advances have resulted in the opening of the deepwater frontier for exploration and development. The 1,200 to 1,500 foot (366 to 457 meter) water depth is generally considered the transition zone between conventional fixed platforms and non-conventional deepwater production systems (tension leg platforms, compliant towers, floating production systems, and subsea systems). The vast majority of Shell's exploration and development activities are concentrated in this latest of deepwater frontiers, where we believe large hydrocarbon accumulations are located. The following comments focus on the need for economic incentives in this area.

In the past nine years, we have drilled 42 exploratory wells on 32 deepwater prospects, setting in 1987 the world deepwater drilling record upon completion of a well on Gulf of Mexico Mississippi Canyon Block 657 in water 1.4 miles (2,293 meters or 7,520 feet) deep. Based on what we know today, Shell is confident this new deepwater frontier holds significant reserve potential as evidenced by our major announced discoveries in the deeper Gulf of Mexico waters -- Bullwinkle, Auger, and Mars.

Bullwinkle is located in 1,353 feet (412 meters) of water on Green Canyon Block 65, about 150 miles southwest of New Orleans. Permanent production facilities were installed in August 1991; and in 1992, the field was producing at an average rate of 52,000 barrels of crude oil and 71 million cubic feet of natural gas per day. Indicating the importance of our deepwater discoveries, daily production from Bullwinkle by 1992 was equivalent to about 12 percent of our domestic crude oil production.

Auger, a $1.2 billion development project, is located in 2,860 feet (872 meters) of water on Garden Banks Block 426, some 214 miles southwest of New Orleans. Tension leg platform installation is scheduled in late 1993 with production beginning shortly thereafter. Production is expected to peak at rates of 46,000 barrels of oil and 125 million cubic feet of gas per day. We have estimated Auger total ultimate recovery at about 220 million barrels of oil and gas equivalent.

In May 1992, we announced a potentially major new deepwater discovery on the Mars prospect, about 130 miles southeast of New Orleans. Located in water over half a mile (3,100 feet or 945 meters) deep, this discovery -- if developed as a commercial field -- would establish a new Gulf of Mexico water depth production record. While we are not prepared to provide a specific range of volumes, our evaluation to date indicates that Mars will significantly surpass in ultimate recovery our Auger prospect. A Mars development decision could be made as early as late 1993.

The need for economic incentives exists in the deepwater Gulf of Mexico frontier despite development of projects such as Bullwinkle and Auger. Both Bullwinkle and Auger contain extremely large hydrocarbon accumulations situated and of a quality which are economic to produce at today's prices. Undoubtedly other large deepwater Gulf of Mexico fields will be justified in the years ahead, possibly Mars. But how many deepwater Gulf of Mexico prospects exist the size and caliber of Auger or Mars? Historically, there have been very few Gulf of Mexico shelf fields the size of these discoveries. The majority of Gulf of Mexico fields are in the 2 - 150 million barrel range with only a limited number of fields in excess of 300 million barrels. If deepwater follows shallow water trends, the vast majority of deepwater prospects would be expected to be smaller than Auger and Mars as exploration expands. Logically, this is what one would expect since industry obviously is exploring and developing what it believes today to be its prime acreage first. Shell is systematically drilling its deepwater leasehold. However, we are skeptical about full development of the deepwater Gulf of Mexico potential for the reasons that follow.

Deepwater economics differ significantly from shallow water. Deepwater projects require large up-front exploration expenditures and prospect delineation costs. Once delineated, the capital investment to develop a typical deepwater project can easily exceed $1 billion, as much as ten times the cost of shallow water projects. Because of facility design, construction, and development complexities, it takes two to three times as long to begin production from a deepwater project versus a shallower water project. In addition, the hydrocarbon recovery period typically is much longer -- about ten years longer to the mid-point of recovery. These factors result in a substantial deferment of return on investment. As a consequence of this deferment, the present dollar value of gas and oil produced in the deepwater is significantly less than shallower water production. Additional complexities and uncertainties related to reservoir performance, long-term natural gas and crude oil prices, hydrocarbon quality, availability of hydrocarbon transportation facilities and support infrastructure, and project cost uncertainties contribute to the economic risk of deepwater projects. Consequently, many prospects will not be economically attractive under current price projections, especially given the production risks associated with this step into the ultra-deepwater and the marginal profitability of many of the prospects. Economic incentives, therefore, will be needed to accelerate and maximize development of these reserves.

H.R. 1282, the Outer Continental Shelf Enhanced Exploration and Deepwater Incentives Act, should stimulate investment in new domestic exploration and production activities by providing a royalty holiday until investment costs are recouped for projects in 200+ meters (656+ feet) of water. The proposal is much needed and is definitely a step in the right direction. While we wholeheartedly support the thrust of H.R. 1282, we do have some suggestions to improve the effectiveness of this legislation and its ability to meet the bill's objective of providing enhanced energy security through incentives to explore and develop frontier areas of the Outer Continental Shelf and to enhance production of the domestic oil and gas resources in deepwater areas of the Outer Continental Shelf.

First, we recommend that it be amended to clarify that all investment costs incurred in a "phased" development program qualify for royalty relief. This clarification is important to Shell because our approach to the development of some deepwater discoveries, if economical, would be in phases. This type of development would be necessary because of the billion dollar plus up-front capital expenditures required to construct and install full permanent facilities in water depths of 1500 feet (457 meters) or greater. As currently envisioned, under a phased development scenario, the initial phase would involve installation of a small structure from which initial production wells would be drilled and produced to test reservoir performance. If the reservoir produces as expected, we would then proceed to the next phase -- construction and installation of permanent production facilities. If all production horizons cannot be reached from these facilities, subsequent phases -- construction and installation of additional production facilities -- might be required. In these water depths, the higher capital outlays are found in the latter phases. If this legislation is to encourage development at this water depth, investment costs in these latter phases must qualify for royalty relief.

Secondly, we strongly recommend that the legislation be amended to include new development activities on leases which are producing prior to enactment of H.R. 1282. As indicated earlier, new three dimensional seismic technology has allowed industry to re-evaluate many known and producing Gulf of Mexico fields along the continental shelf. New production horizons untapped by existing platforms and wells are being found. We expect the same result when this technology is applied to leases on production today in approximately 1,000+ feet (305+ meters) of water. Royalty relief until investment costs are recouped should provide the encouragement to allow a number of these projects to go forward.

Again, H.R. 1282 is a step in the right direction to encourage development of deepwater potential. However, a broad range of incentives will be needed if the Nation is to take full advantage of this significant new source of domestic oil and gas. A June 24, 1993 DRI/McGraw-Hill report, "National Economic Impacts of an Oil/Gas Production Tax Credit to Stimulate Deepwater Exploration and Development", presented the results of a DRI/McGraw-Hill economic analysis of the potential impacts resulting from domestic Gulf of Mexico deepwater oil and gas exploration and development stimulated by a federal production tax credit incentive of $5 per barrel oil equivalent. Such an incentive was contained in bill S. 403, introduced February 17, 1993 by Senator Breaux. An assumed volume of 9 billion barrels oil equivalent of incremental deepwater reserves developed as a result of the incentive, as well as resulting production (peaks at 860,000 barrels oil equivalent per day), and investment and operating cost information were supplied DRI by selected companies engaged in deepwater exploration and development. Energy prices were based on the National Petroleum Council's 1992 natural gas study "low reference case". The study covered a 25-year time frame (through 2017). The economic impacts on specific Gulf coast region states (Louisiana, Texas, Oklahoma, Alabama, and Mississippi) were also examined in an adjunct report (dated July 9, 1993). Among the key conclusions of the study are:

- Up to 100,000 new jobs created near term (by 1998) with 60,000 to 80,000 jobs sustained through the end of the study period.
- Annual real GDP increased by $4 - $8 billion (1987 dollars) in 1998, increasing to $20 billion by 2017.
- Cumulative federal revenues increased $6 - $10 billion by 1998 (nominal dollars) with total net revenues reaching $330 - $375 billion by 2017 (net of the tax incentive).
- Federal debt reduced $5 - $9 billion (nominal dollars) by 1998 with total debt reductions reaching $213 - $234 billion by 2017.
- Annual foreign trade balance improved by $23 billion in 2017 (nominal dollars).

The DRI/McGraw-Hill study clearly indicates that a $5 per barrel oil equivalent production tax credit incentive would result in a win-win economic benefit for the Nation as a whole and the industry while adding significantly to the domestic supply of oil and gas. The productior tax credit should be given serious consideration as one of a broad range of incentives which will be needed to accelerate development of the deepwater Gulf of Mexico, create jobs, stimulate the economy, reduce the trade deficit and sustain Gulf of Mexico production into the next century.

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